Second Wallace E. Pratt Conference
"Petroleum Provinces of the 21st Century"

Petroleum Provinces of Canada for the 21st Century [1]

by Keith Skipper [2]

ABSTRACT

Remaining reserves of marketable crude oil and natural gas in Canada are in excess of 1.43 x 10^9 m^3 (9 billion barrels) and 1.84 x 10^{12} m^3 (65 trillion cubic feet (Tcf). These reserves enable current annual extraction rates of 127 x 10^6 m^3 (800 million barrels) of oil and 170 x $10^9 m^3$ (6 Tcf) of natural gas, mainly from the mature Western Canada Sedimentary Basin. In the next millennium, expanded contributions to production capacity will come initially from the Mesozoic Jeanne d'Arc Basin (e.g. Hibernia & Terra Nova oil) offshore Newfoundland and basins off Nova Scotia (e.g. Sable Island gas). In northern Alberta, additional investment in exploiting the Cretaceous oil sands will enhance the production of upgraded (synthetic) crude oil, bitumen and heavy oil.

Notwithstanding the technical and commercial challenges, predictions of remaining exploitable resources in accessible areas exceed 5.6 x 10^{12} m^3 (200 Tcf) of gas and 16 x 10^9 m^3 (100 billion barrels) of bitumen. In addition to oil sands, tight gas and coalbed methane in the Western Canada Sedimentary Basin, significant undeveloped resources are known in the remote Canadian Arctic islands (Sverdrup Basin), the Labrador shelf (gas) and the Beaufort Basin (gas and oil). Many of these resources will remain "orphaned", depending on environmental aspects, delivery costs, markets and commodity price. Current "stranded gas" in the Mackenzie Delta and the shallow offshore waters of the Beaufort Sea could be connected (via the Mackenzie Valley corridor) to the natural gas pipeline grid serving domestic and United States markets. Associated gas reserves (presently re-injected at Hibernia) in the Jeanne d'Arc Basin, if not connected to shore by pipeline, may be developed using either natural gas to liquid conversion or compressed gas transport technologies.

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INTRODUCTION

Canada (see Energy Information Administration, 1999; World Energy Council, 1999; BP, 1999; see also Canadian Association of Petroleum Producers, 1999a) is the world's third largest producer of natural gas (8% production share from 1.3% of the world's proven gas reserves) and eleventh largest producer of crude oil (0.6% of the world's proven reserves), with huge undeveloped future energy resources. To date, production in Canada has recovered over 3.3×10^9 m^3 (21 billion barrels) of oil and 3.2×10^{12} m^3 (114 Tcf) of natural gas. Remaining reserves of marketable crude oil and natural gas ("booked reserves") are in excess of $1.4 \times 10^9 m^3$ (9 billion barrels) and 1.84×10^{12} m^3 (65 trillion cubic feet (Tcf)). These reserves enable current annual extraction rates of $127 \times 10^6 m^3$ (800 million barrels) of oil and $170 \times 10^9 m^3$ (6 Tcf) of natural gas mainly from the mature Western Canada Sedimentary Basin. Total liquids production including conventional, synthetic (upgraded), heavy crudes and natural gas liquids (or NGL's) reached a record $424 \times 10^3 m^3 / d$ or 2.67 million barrels per day in 1998 (Roberge, 1999). Undeveloped discovered resources, including "stranded gas" and static heavy oil and bitumen resources (Imperial, 1999a or b), are capable of sustaining greater extraction rates provided economic (including availability of investment capital) and technical hurdles are continuously overcome. Canadian producers must compete with the industry's pursuit of high volumes of production at a low per unit cost – an efficiency driven by volatile commodity prices.

To facilitate the discussion which follows, Figure 1 portrays the location of the major sedimentary basins in Canada. Numerous publications detail the specific tectonic elements, stratigraphy, sedimentology, geochemistry and resource endowment of these basins; far too voluminous to be quoted here. Nevertheless, the references cited may allow the interested reader to wade into specific elements of interest. Significant resources discovered to date in Canada are highlighted in Figure 2.

Multitudes of studies are directed at the remaining petroleum resource potential of Canada by government, industry sponsored and private individuals (see, for example, Young and Drummond, 1994). These studies cover the mature producing basins (e.g. Western Canada Sedimentary Basin), Canada's new evolving areas of production (Atlantic margin or "East Coast") and its frontier areas (e.g. Mackenzie Delta and Beaufort Sea). A large body of literature exists which is transparent and amenable to analysis and comment. Nevertheless, exploration activities and discoveries to enhance the fundamental analysis in the Canadian frontiers, over and above those reported by Meneley (1986) and Grant, McAlpine and Wade (1984) in the inaugural Wallace E. Pratt Memorial Conference, have not occurred. Both papers remain excellent primers on which to build subsequent analysis. Indeed, the development, and enhancement of early discoveries in the Canadian frontiers (including those in the Mackenzie Delta, Beaufort Sea, Arctic Islands, and Grand Banks) has not progressed as much as visionaries thought they might in the early 1980's. Native people's issues, moratoria, low prices, lack of available capital, better economic returns elsewhere in traditional basins (e.g. the Western Canada Sedimentary Basin), lack of clear Canadian federal and provincial government fiscal policies, harsh environmental conditions, amongst other factors, have stalled investment.

Resource Numbers Quoted

Any discussion of ultimate resource endowments are based on many different assumptions which are dynamic, continue to evolve with new petroleum discoveries, different perceptions of technology enhancements and applications, economic projections, fiscal tax and incentive regimes and time of assessment. Figures quoted herein are sourced from a variety of publications and websites and caution is advised in the repeatability and application of these estimates. Figures assigned to Geological Survey of Canada publications frequently use probabilistic methods for estimating resource endowment; others may use Delphi approaches (Canadian Gas Potential Committee, 1997) or hybrid schemes. Estimates for some areas (e.g. Western Canada Sedimentary Basin) have a habit of increasing in magnitude over time (Drummond, 1995)

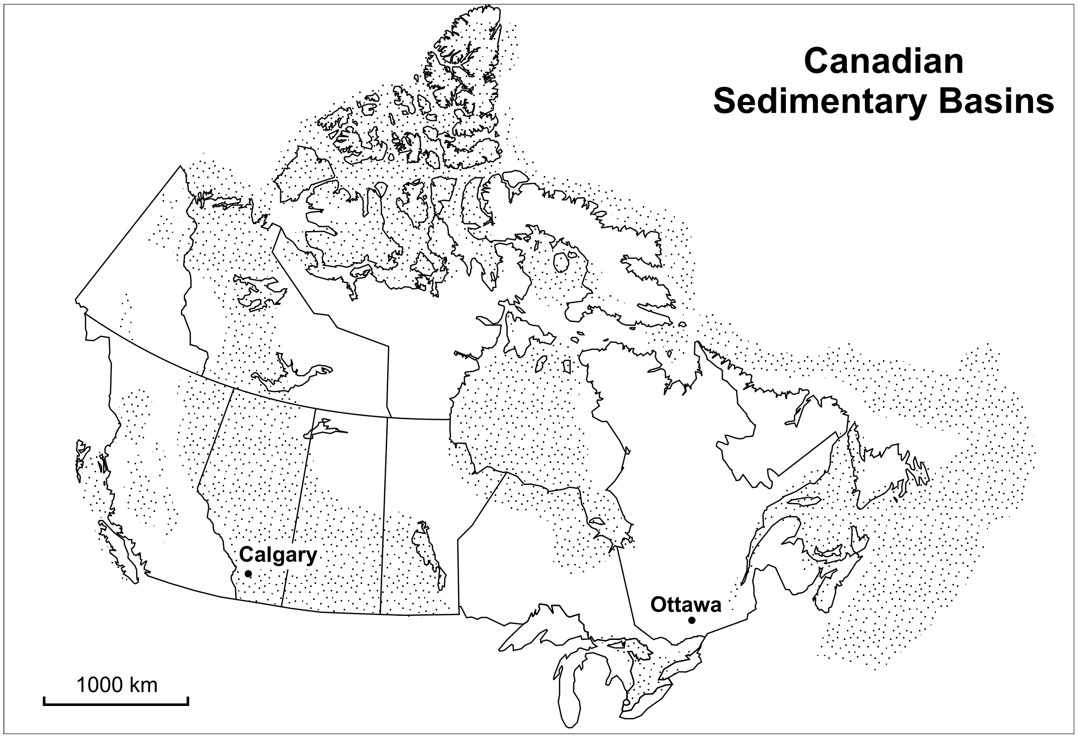

Figure – Sedimentary Basins of Canada. Sverdrup is the major basin of interest in the Canadian Arctic islands. Labrador includes the Hopedale Basin. Jeanne d'Arc is the most important basin on the Grand Banks. The basins of the Pacific Margin and Georges Bank off eastern Canada are subject to existing moratoria.

while others are severely reduced as early optimism is tainted by the realities of the producing environment, the commodity market and pricing. In this paper, estimates are utilized wholesale as of reference date. They should be viewed as giving an order of magnitude developed by informed scientists and practitioners and the figures may be useful in global analyses, comparisons and strategic planning.

ORIGINAL IN-PLACE RESOURCES IN CANADA

The primary source document for the present status of petroleum resource assessment in Canada is a report by the National Energy Board on energy supply and demand to 2025 (NEB, 1999a). For crude oil this report also updates the compilation by Lee (1998). The latest assessment of natural gas resources (estimated to year-end 1993) is by the Canadian Gas Potential Committee (1997), which report itself, is under revision. An earlier overall assessment by the Geological Survey of Canada was by Proctor, Taylor and Wade (1983).

Conventional Crude Oil Resources

Original oil in-place in Canada is estimated to at 34.4 $x10^9 m^3$ (216 x 10^9 barrels) of which 9.2 $x10^9 m^3$ (58 $x10^9$ barrels), or 27%, is estimated to be ultimately recoverable and marketable (NEB, 1999a). The figure for recoverable oil compares with an estimated 13 x $10^9 m^3$ (85 x 10^9 barrels) in 1973 (McCrossan and Porter in McCrossan, 1973, p.704) and a speculative estimate of 9.0 x $10^9 m^3$ (56 x 10^9 barrels) by Proctor, Taylor and Wade, 1984, p.53)

Unconventional Crude Oil Resources

Unconventional resources of crude oil consist entirely of bitumen, estimated to be 400 x 10^9 m^3 (2.5 x 10^{12} barrels) of which 49 x 10^9 m^3 (300 x10^9 barrels) is considered ultimately recoverable (NEB, 1999a).

Conventional Natural Gas Resources

Ultimate recoverable and marketable resources of natural gas are estimated to be in the range of 660 (18.7 x$10^{12}m^3$) - 730 Tcf (20.7 x $10^{12}m^3$), (NEB, 1999a) depending on its price. This figure compares to a 1973 estimate of 16.3 x $10^{12}m^3$ (577Tcf) by McCrossan and Porter (in McCrossan 1973, p.704) and 18.2 x $10^{12}m^3$ (642 Tcf) by Proctor, Taylor and Wade (1984). However, 45-50%, or 8.5 x 10^{12} m^3 (303 Tcf), is ascribed to frontier areas which include the Arctic Islands, Labrador and the Mackenzie Delta/Beaufort Sea (see also Young and Drummond, 1994; Drummond, 1998). Since frontier resources are high cost, remote, or located in inaccessible areas which would 'have no greater opportunities for exploitation than unconventional natural gas resources in the Western Canada Sedimentary basin' (Young and Drummond, 1994 p.10), some should be deleted from the potential marketable resource base. The Canadian Gas Potential Committee (1997) concluded an undiscovered conventional marketable gas estimate of 3.4 x 10^{12} m^3 (122 Tcf) for the Western Canada Sedimentary Basin, and 1.8 x $10^{12}m^3$ (63 Tcf) for the frontier areas. Remaining marketable conventional gas resources are quoted as 5.2 x $10^{12}m^3$ (185 Tcf) in producing areas and 3 x10^{12} m^3 (107 Tcf) in non-producing areas (Canadian Gas Potential Committee, 1997 table 1-A and 1-B, p.1). Of this total, 866 x 10^9m^3 (30.4 Tcf) was assigned to Labrador and the Sverdrup Basin; these are unlikely to be accessed within any current forecast span. The largest potential is recognized in the Beaufort Basin at approximately 1.6 x 10^{12} m^3 (56 Tcf).

Unconventional Natural Gas Resources

Unconventional gas resources in Canada include coalbed methane, tight gas reservoirs, shales' gas and hydrates. Comments are made here only about coalbed methane and tight gas reservoirs.

Great uncertainty exists as to the appropriate estimate of in-place resources of combustible natural gas (methane) associated with coal beds (or CBM). Canada, in particular in the Western Canada Sedimentary Basin, has vast quantities of coal measures which might offer the opportunity for methane desorption and production (Dawson, 1995). Ranges are highly variable and speculative. Coalbed methane resources of the Cretaceous Upper Mannville in Alberta have been estimated at more than 4.5 x $10^{12}m^3$ (more than 160 Tcf) of gas (Langenberg, Rottenfusser and Richardson, 1997). The Canadian Gas Potential Committee (Canadian Gas Potential Committee, 1997) quoted recoverable resources of 135 to 261 Tcf. Nevertheless, the National Energy Board (NEB, 1999a) have assumed a resource of 2.1 x $10^{12}m^3$ (75 Tcf) may be recoverable, but Young and Drummond (1994) limits the figure to 570 x10^9m^3 (20 Tcf). If technology works and investment is available, the recoverable CBM resource may be large (say > 2.8 x $10^{12}m^3$ or 100Tcf). Further analysis and pilot projects are required to ascertain the viability of such production. Coalbed methane extraction is notorious for being site or field specific and further work is required in Canada to justify present assumptions and projections.

However, projections on the supply of gas produced in the Western Canada Sedimentary Basin requires and assumes production rates from CBM of over 283 x 10^6m^3 per day (10 Bcf per day) by 2025 (NEB, 1999a). Tardy development of CBM production (or alternative sources of gas supply) therefore implies shortfalls against a planning scenario requiring such supply. The early development of Mackenzie Delta conventional

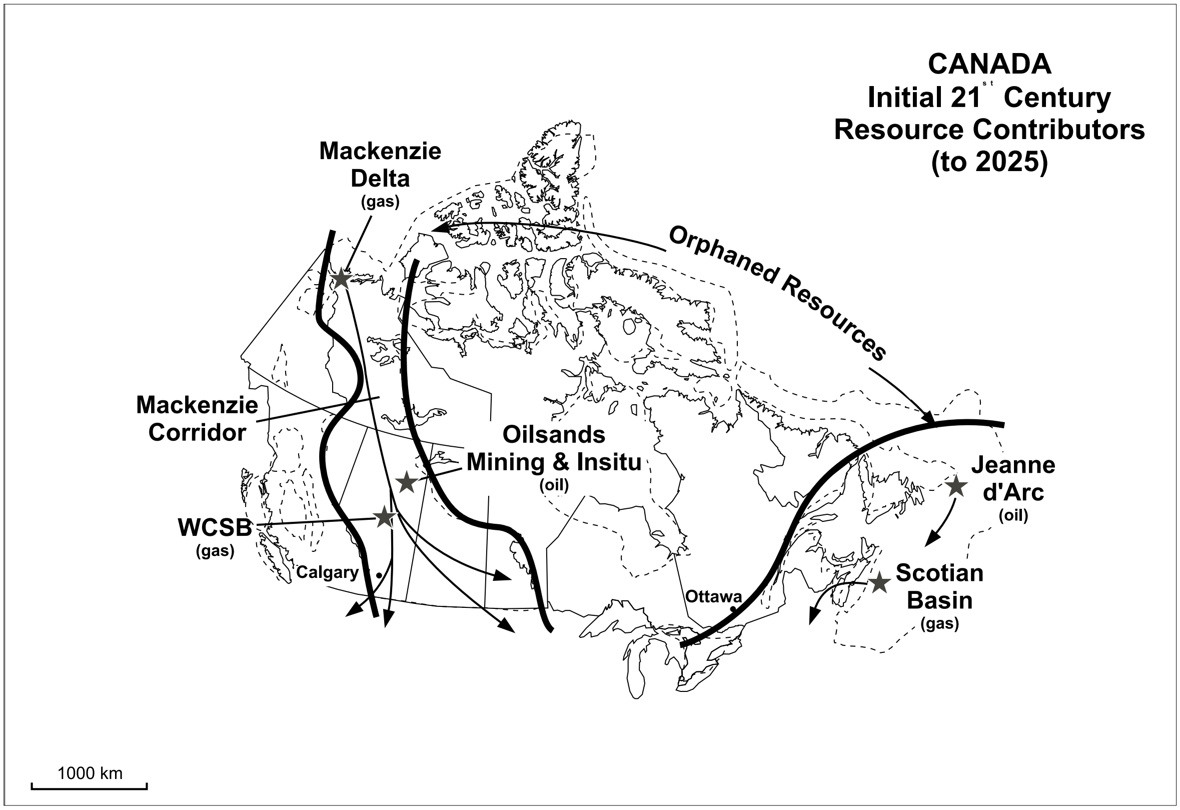

Figure 2 – Location of Significant Resources of Canada as defined to date. Exploration activities have been conducted in all areas considered to offer the potential for major discoveries. Drake Point (170 x 109m3 or 6Tcf) is the largest undeveloped gas discovery in Canada; Amauligak is the largest oil discovery in the Beaufort Sea; Taglu is the largest gas discovery on the Tuktoyaktuk Peninsula; the WSCB (Western Canada Sedimentary Basin) has produced the bulk of Canada's petroleum resources to date and is the site of the Athabasca oilsands; Venture is the largest gas field on the Scotian Shelf and underpins the Sable Island gas development inaugurated in late 1999; Hibernia in the Jeanne d'Arc Basin is the first oilfield to be developed on the Grand Banks; Bjarni is the largest gas discovery offshore Labrador.

natural gas may delay the need for early CBM or other unconventional natural gas production.

Tight gas reservoirs, particular tight or very low permeability gas sands, are very prevalent in the Western Canada Sedimentary Basin and have been discussed by Masters (1984) as "Deep Basin" resources. Estimates vary but the resource may be large: from 175 to 3,500 Tcf (Canadian Gas Potential Committee, 1997, p.3).

Production from unconventional gas resources is particularly responsive to changes in assumed levels of technological progress and commodity price. Tax (fiscal) incentives might accelerate industry interest and investment. None of the resources discussed above are considered economically recoverable at this time.

PRODUCTION OF PETROLEUM IN CANADA

Cumulative Production to date

Estimates of cumulative production to year-end 1999 of conventional crude oil are $3 \times 10^9 m^3$ (18.5 billion barrels) and $397 \times 10^6 m^3$ (2.5 billion barrels) of liquid petroleum products from oil sands.

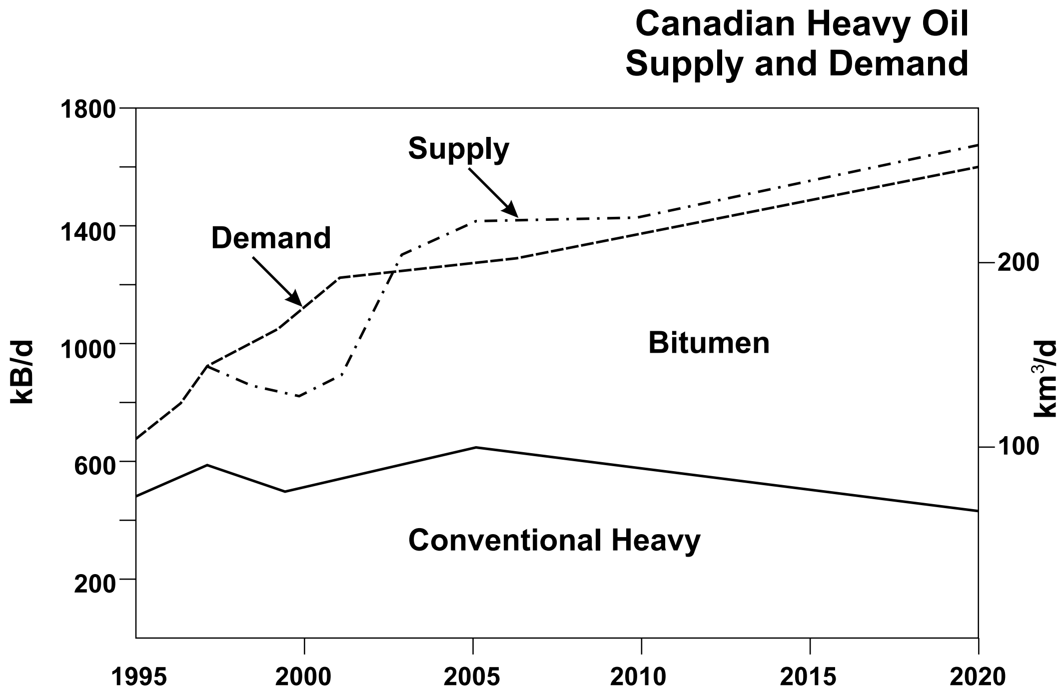

Figure 3 – Canadian heavy oil supply and demand (modified after Dingle, 1999a)

Total production of marketable natural gas is estimated at 3.2 x $10^{12}m^3$ (114 Tcf).

Production, Year 2000

Canada currently (1998 figures) produces 127 x 10^6m^3 (800 million barrels) of crude oil per annum or 350 x 10^3m^3 (2.2 million barrels) a day (conventional light and heavy, synthetic, bitumen, and pentanes plus) and 170 x 10^9m^3 (six trillion cubic feet) per annum, or 467 x 10^6m^3 (16.5 Bcf) per day, of natural gas. Exports, mainly to the United States, approximate 85 x 10^9m^3 (3.0 Tcf) on an annual basis and 222 x 10^3m^3 (1.4 x 10^6 barrels) of crude oil per day (Canadian Association of Petroleum Producers, 1999a).

Conventional production

Canada currently produces approximately 253 x 10^3m^3 (1.6 million barrels) a day of conventional crude oil (which includes both light and heavy conventional crude oil and condensate) (Canadian Association of Petroleum Producers, 1999b). The majority of this production comes from the Western Canada Sedimentary basin, mainly Alberta, with minor contributions from Ontario.

Frontier Production

The Hibernia crude oil project, located offshore Newfoundland and Canada's first large-scale offshore development, came on-stream in late 1997. At year-end 1999, Hibernia is producing 23,800 m^3 (150,000 barrels) of conventional light crude oil per day. Cohasset/Panuke, located offshore Nova Scotia has been on production

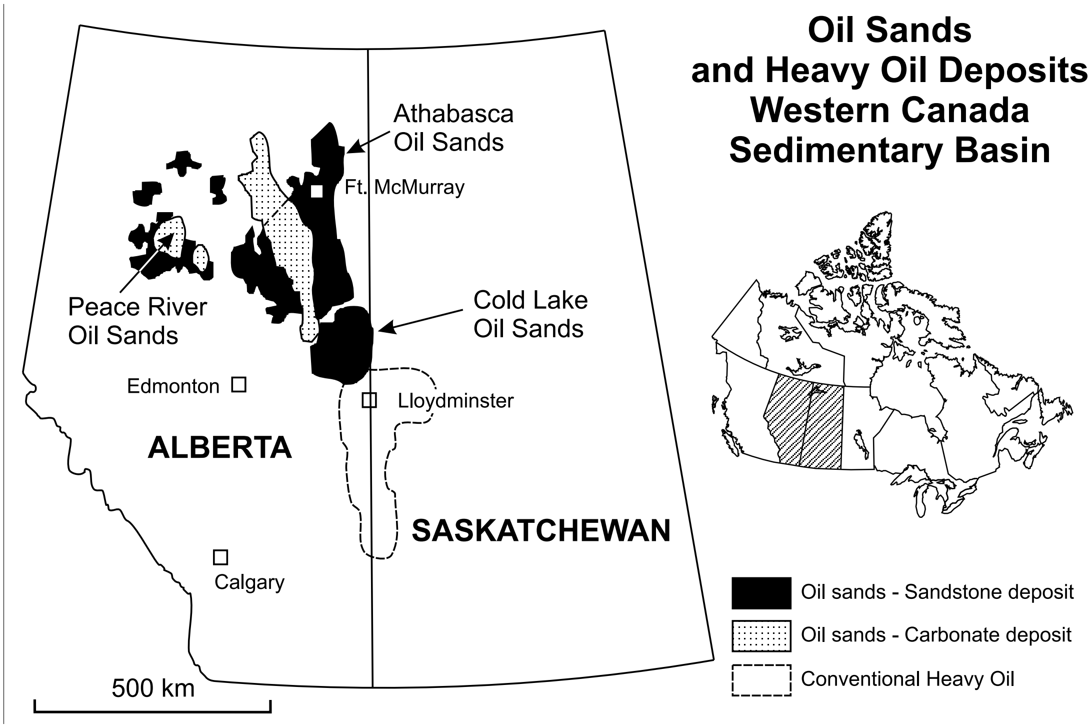

Figure 4 – Location of the oilsands and heavy oil deposits in the Western Canada Sedimentary Basin. Llyodminster is the location of major upgrading facilities. Ft McMurray is the location of all the integrated mining plants (e.g. Syncrude and Suncor).

since 1992. It was the first commercial oil development in the Atlantic Canada offshore and is expected to be abandoned in 2000. Cumulative production to abandonment is expected to be approximately 7.3 x $10^6 m^3$ or 46 million barrels (Newfoundland Ocean Industries Association, 1998, section 2.3).

Production of natural gas commenced in November 1999 from the Sable Island project, offshore Nova Scotia. Initial rates of gas production are expected to reach 500 MMcf per day.

During 1999, modest gas production commenced from Inuvialuit Petroleum Corporation's Ikhail gas development (396 x $10^6 m^3$ or 14 Bcf of recoverable sales gas), in the Mackenzie Delta (see Figure 9) delivering gas at a rate of 2 MMcfd to Inuviuk (Northern Oil and Gas Directorate, 1999).

Oil sands or non conventional Production

Today, 14% of the total annual oil production in Canada or 51,587 m^3 (325,000 barrels) per day is synthetic (or more correctly, "upgraded") crude oil produced from two large integrated oilsands mining operations. A further 13% of annual production or 44,000 m^3 (280,000 barrels) per day, is sold directly as bitumen (Figure 4). The production of heavy oil, bitumen and upgraded crude accounts for 36% of current Canadian liquids supply.

CANADIAN RESERVES-YEAR 2000

Crude Oil

At year end 1999, remaining reserves of conventional crude oil and equivalent are estimated at 714 x $10^6 m^3$ (4.5 billion barrels). Natural gas liquids reserves are estimated at 103 x $10^6 m^3$ (650 million barrels). Remaining reserves of developed oil sands, both integrated mining and insitu bitumen, are estimated at 635 x $10^6 m^3$ (4.0 billion barrels).

Natural Gas

At year-end 1999, reserves of marketable natural gas are estimated at 1.84 x $10^{12} m^3$ (65 Tcf), consisting of 1.6 x 10^{12}m3 (56.5 Tcf - 87% of total) in the Western Canada Sedimentary Basin.

EXPORT CAPACITY-GAS

Canada is a major exporter of natural gas to the US market. Indeed, natural gas is truly a North American commodity. Present export capacity as measured by cross boarder pipeline capacity is approximately 339 x $10^6 m^3$/d or 12 Bcf/d. With the completion of all currently planned and constructed facilities, including the Alliance Pipeline (see below) capacity of 452 x $10^6 m^3$/d or 16 Bcf/d would be available. By 2000, export capacity from Canada will be about 42% of the export capacity from the US southwest (Gulf Coast) (EIA, 1998). Whether it will be profitable or the gas available to fill these pipelines is a topical issue.

RECENT AND CURRENT PROJECTS

Recent "high impact" developments on Canadian conventional production have centered on discoveries made over 20 years ago, during the late 1960's and the 1970's. The industry struggles with severe operating conditions, attempts to lower its cost base and, potentially, marginal full cycle economics. This is likely to continue to challenge investment planning and the timing of investment.

East Coast

On the East Coast (or Atlantic Canada) several major projects have recently commenced production, are under development or in advanced stages of pre-building (see Government of Newfoundland and Labrador, 1999). These are: Hibernia oil field situated in the Jeanne d'Arc Basin on the Grand Banks, off Newfoundland; the Sable Offshore Energy Project being developed to deliver natural gas from six offshore gasfields off the coast of Nova Scotia (see Sable Offshore Energy Incorporated, 1999); the Terra Nova oilfield development, also in the Jeanne d'Arc Basin. Drilling operations at White Rose (gas and oil) during 1999 may also lead to early disclosure of development plans.

Hibernia

The Hibernia oilfield, discovered in 1979, is located in 80m (262 ft) of water, 315 km (195 mi) east-southeast of St. John's Newfoundland (Mackay and Tankard, 1990). It is the first development of a Gravity Based Platform to be designed to withstand a direct Impact with an iceberg. Cost for development has been quoted at C$5.8 billion. Total oil-in-place is estimated at 476 X $10^6 m^3$ (3 billion barrels) with in excess of 97.6 X $10^6 m^3$ (615 million barrels) recoverable. Production commenced in late 1997 and production has been building since then to a plateau of 21.5 x $10^3 m^3$ (135,000 bbl/d). Hibernia crude oil is 32-34 degrees API with low sulphur (Hibernia, 1999a). Its production is offloaded from on site storage to shuttle tankers; it is not piped to shore due to difficulties and risk from ice scouring the seabed. The development of satellite fields, which require tieback to Hibernia later in its field life, will need buried umbilicals to drain them.

The Sable Offshore Energy Project

The Sable Offshore Energy Project, consists of six fields: Venture, South Venture, Thebaud, North Triumph, Glenelg and Alma. These fields are located 225 km (140 mi) offshore Nova Scotia near Sable Island (see Figure 8, notation Venture et al). Cost of the first phase development is $2.0 billion (Owens, 1999). The project has recoverable reserves of 100 x $10^9 m^3$ (3.5 Tcf), and raw gas production is estimated to commence at 500 million cubic feet per day and 20,000 per day of natural gas liquids (November 1999 - see Sable Offshore Energy Incorporated, 1999 and Owens, 1999).

Terra Nova

The Terra Nova field, discovered in 1884, is located 350 km (220 mi) east-southeast of St. John's, Newfoundland in 95m (312 feet) of water and about 35 km (22 mi) east of Hibernia. Unlike Hibernia, it is being developed via Floating Production Storage and Offloading (FPSO) facility. Total recoverable reserves are estimated at 59 x $10^6 m^3$ (370 million barrels), but could reach 92 x $10^6 m^3$ (580 million barrels). Initial production is targeted for late 2000 commencing at 18.2 x $10^3 m^3$ per day (115,000 bopd), (Terra Nova, 1999).

White Rose

First discovered in 1987, Husky Oil Ltd drilled three successful wells in 1999 in the White Rose field and resource indications suggest recoverable hydrocarbon volumes of 40 x $10^6 m^3$ (250 million barrels) of oil (South White Rose) and 42 x $10^9 m^3$ (1.5 Tcf) of gas (North White Rose has 150 million barrels recoverable of natural gas liquids and 2 Tcf). Announcements are imminent as to development plans and economic viability.

Western Canada

In western Canada, major projects include additional pipeline construction to enhance the capability to deliver more natural gas into the mid west US markets (Chicago). Major investments are also being made in expanding existing oilsands mining operations and the construction of new mines.

The Alliance pipeline

The Alliance pipeline (Alliance, 1999) is a major pipeline (US$3.0 billion) being constructed to move natural gas from northeastern British Columbia to the Chicago, Illinois area market where it will connect into the North American gas pipeline grid. Total distance is 2990 km (1858 mi), the longest pipeline ever-built in North America. Initial throughput will be 37.5 x $10^6 m^3$ (1.325 billion cubic feet) per day. Completion is scheduled for November 2000.

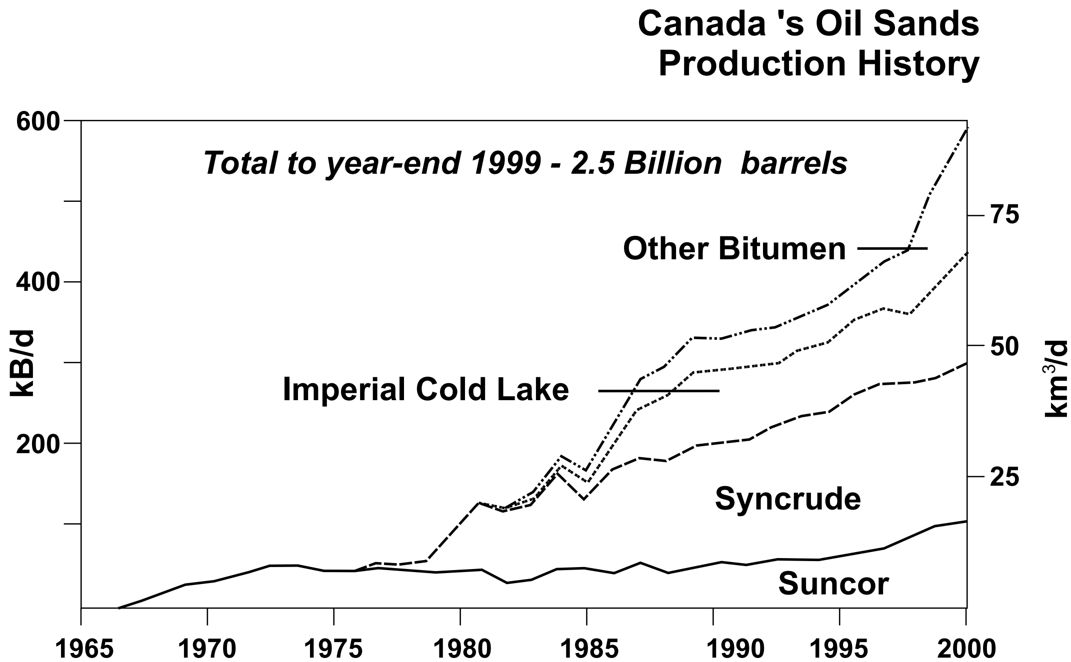

Figure 5 – Canada’s oilsands production history.

Oilsands upgrades, expansion and new mines

The two existing miners of oilsands, Suncor and Syncrude, are constructing expansions to their present mining and upgrading operations. Suncor (see Suncor, 1999) has the Millennium project by which it will expand its production to 35,000 m^3/d (220,000 bopd) from the current 16,600 m^3/d (105,000 bopd) by 2002. Reserve life at Suncor’s new Steepbank mine is 35 years. Syncrude is extracting from the new North Mine and constructing the Aurora mine and expects to lift its production from present 35,000 m^3/d (220,000 bopd) to over 76,000 m^3/d (480,000 bopd) by 2007 or 23.8 x $10^6 m^3$ (150 million barrels) per annum at a cost of C$6.0 billion (see Syncrude, 1999). Shell has also plans to develop the Muskeg mine with capacity for 23,800 m^3/d (150,000 bopd) in 2002 at a price tag of $3.4 billion. All of these developments will mean that production targets of over 80,000 m^3/d (500,000 bopd) may be attainable by 2005. They are capital intensive and are the foundation for additional supplies of Canadian petroleum to reach markets in the 21st Century.

SEDIMENTARY BASINS OF CANADA

Canada has over 6.5 million km^2 (2.5 million mi^2) of prospective sedimentary section in 38 unmetamorphosed basins (see McGrossan, 1973, p.4) with approximately 60 % onshore.

The most important and familiar basins to petroleum geologists are the Western Canada Sedimentary Basin, Ontario, Jeanne d’Arc, Mackenzie Delta, Beaufort and Sverdrup (Arctic islands) basins. (Figure 1). The geographic location of the frontier basins of Mackenzie, Beaufort, Sverdrup, Labrador, and Jeanne d’Arc has required some innovative and expensive developments of drilling capabilities to evaluate them. Environments are harsh and the costs of exploitation remain prohibitive for some. All favored basins are reasonably well known in terms of their potential petroleum endowment and all have been the subject of exhaustive studies. Databases on all the frontier basins are arguably adequate to define the scale and nature

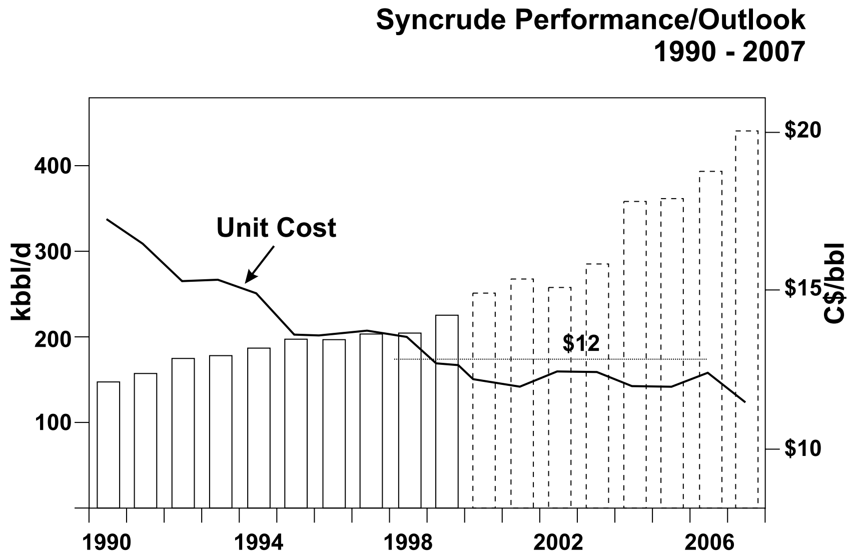

Figure 6 – Syncrude performance and outlook. Note the operating cost per unit of production has now fallen to approximately C$12.00 per barrel. This figure excludes capital recovery.

of the resource. Substantial work has focused on locating and analyzing favorable ”world-class?” source rocks and some areas worthy of potential wildcat evaluation have been suggested. However, these areas are unlikely to attract industry investment until other opportunities (both North American and foreign) appear remote and less valuable.

Western Canada Sedimentary Basin

The Western Canada Sedimentary Basin (WSCB or Alberta Basin, Province Code 5243, USGS, 1997) occupies an area of 1.4 million km^2 (540,000 mi^2) of southwestern Manitoba, southern Saskatchewan, Alberta, north-eastern British Columbia and the southwest corner of the Northwest and Yukon Territories (see Mackenzie Valley below). Petroleum resources of the basin range from natural gas, conventional light oil to bitumen (a good summary is provided by Johnson and McMillan, 1993). The basin is situated between the deformed Cordilleran Belt to the west and the Precambrian (or Canadian) Shield to the east (Barclay and Smith, 1992; Mossop and Shetsoen, 1994, Ricketts, 1989). The Western Canada Sedimentary Basin has been responsible for over 90% of the 21 billion barrels of crude oil produced in Canada since 1856, when initial discoveries and production commenced in Ontario from Silurian reefs.

It is only in the Western Canada Sedimentary Basin that the petroleum industry comes close to a “just in time” inventory business, with operators able to shift rapidly the drilling for oil to gas (as occurred in 1998) and vice versa.

A total of ten marine, petroleum source rocks ranging in age from Middle Devonian to late Cretaceous exist within the basin. Principal hydrocarbon reservoirs occur in the Lower Cretaceous Mannville Group and sub-cropping Paleozoic carbonates (Creaney and Allan, 1990) or Devonian (reefs) (Geological Atlas of Western Canada Sedimentary Basin, 1998).

Natural gas

Characteristics of natural gas production from the Western Canada Sedimentary Basin are:

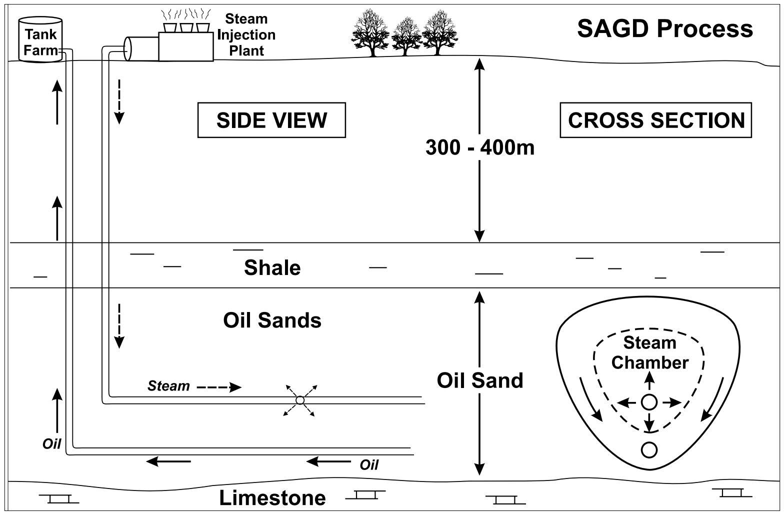

Figure 7 – The Steam Assisted Gravity Drainage or SAGD process for in-situ recovery of bitumen (oil) from oilsands.

- Production in Alberta of 4.7 Tcf per annum (1997) accounts for 80% of total Canadian natural gas production.
- the small size of the recoverable reserve per well (Samson, 1999; Samson and Kirsch, 1999).
- rapid decline in the annual rate of production per well.
- at the moment (1999), pipeline capacity exceeds supply.
- the requirement to retain a high rate or intensity of drilling per annum to replace produced reserves and capture markets.
- midstream rationalization bringing greater efficiency into the use of plants, pipelines and facilities (decline rates may cause facilities to be underutilized).
- gradual “infrastructure creep” into the northernmost reaches of the Basin, beyond latitude 60 degrees North.

Commensurate with the maturity of the exploration in the basin, median gas reserves per discovery well today are less than 28.3 x $10^6 m^3$ (1 Bcf). Statistical analysis by Drummond (personal communication 1999) indicates this pattern is unlikely to change into the next century. Only 3 pools have been discovered in the last 10 years have been greater than 1.5 x $10^9 m^3$ (52 Bcf) when booked back to their discovery date (Samson and Kirsch, 1999). Of a quoted 4.1 x $10^{12} m^3$ (148 Tcf) marketable natural gas, 82% was discovered before 1980 (Drummond, 1995) with the average pool size being 161 x $10^6 m^3$ (5.7 Bcf). Since 1980, the average pool size has been just over 59 x $10^6 m^3$ or 2.1 Bcf (Young and Drummond, 1994, p.17).

The high rates of natural gas extraction from the basin is underpinned by 45, 000 currently connected and producing wells. Production rates from these wells (1997 figures) will decline from 15.3 Bcf/d (430 x 10^6 m^3/d) to approximately 8.0 Bcf/d (225 x 10^6 m^3/d) in 2001 and will contribute less than 50% of total gas demand or deliverability in 2001. Wells connected since 1994, contribute about 50% of the current Western Canada Sedimentary Basin production (NEB, 1999b).

In 1997, the initial capability of the average producing gas well was 35.7 X$10^3 m^3$ per day (1.26 million cubic feet per day) (Samson, 1999) Current rates of drilling must be increased in order to meet future demand (NEB, 1999b, p.21). Studies indicate rapid decline rates for a majority of the wells with a 95% probability of any new well being depleted and abandoned within 4 years of connection. Considerable potential for gas remains in the basin however, with discovery trends implying that the approach of the asymptotic limit is some way off (Drummond, personal communication, 1999). To date the basin is recognized to contain remaining identified marketable gas reserves of 1.7 x $10^{12}m^3$ (60Tcf) with an ultimate potential of approximately 5.6 x $10^{12}m^3$ (200Tcf), of which over 2.8 x $10^{12}m^3$ (100 Tcf) has been produced to date. Depending on gas pricing, mean estimates of economically recoverable conventional undiscovered natural gas resources for the WCSB range from 3.9 x $10^{12}m^3$ (140 Tcf - gas plant gate price of $3.00) to 849 x 10^9m^3 (30 Tcf - gas plant gate price of $1.00) (Conn et al, 1995).

There appears to be little in the way of new geological concepts which will enhance these numbers irrespective of wellhead gas prices. The basin is clearly mature and in the drill-out phase. Decline rates for gas wells connected since 1988 show decline rates of about 35% per year (NEB, 1999b). However, the potential for significant contributions to Canada's natural gas remains well into the next millennium and with midstream and other producing efficiencies, significant economic rewards await lowest cost producers. Potential will be found in thousands of relatively small gas pools. To maintain production and reserve to production cover ratio, over 5,000 gaswell completions will be required in the near term (NEB, 1999b). Concerns do exist about the capacity of the Western Canada Sedimentary Basin to deliver gas in the volumes required through the next two decades, but National Energy Board consultations with industry indicate gas from unconventional resources, such as coalbed methane, may attain 283 x 10^6m^3/d (10Bcf/d) by 2025. Some concern might be expressed about the sustainability of production at these rates. Non-conventional production would then constitute 37% of total estimated production. Conventional gas production is expected to reach its maximum in 2008.

Remaining big potential in Western Canada Sedimentary Basin will be in the Foothills and deep Devonian plays. These areas have high potential but also higher costs. Statistics suggest 95% of all future discoveries will be less than 283 x 10^6m^3 (10 Bcf).

With the major decrease in pool size, the intensity of exploration activity and the finding and connecting rate will impact deliverability of new gas supplies. Better prices and netbacks to industry will promote deeper drilling and improved technologies will enhance production. However, projections made about the need to increase deep drilling in the deeper parts of the Western Canada Sedimentary Basin and the foothills, implies that industry has been complacent both in the application of technology (portable 3D) and in defining drilling targets in those areas. This may not be the case since major players have shunned shallow gas drilling due to high overheads, low flow rates, and small additions to their reserve bases (low reserve/production ratios). The industry has kept up the pace to seek out large prizes in the deeper portions of the Western Canada Sedimentary Basin.

Light oil

Major characteristics of light oil production in the Western Canada Sedimentary basin are:

(a) the absolute magnitude of annual production has been in decline for several years – the trend appears irreversible.

(b) the average oil well is today producing less than 7.9 m^3 (50 barrels) of oil per day (compare with average in US of 1.8 m^3/d or 11.5 bopd (1998)).

(c) light oil production in the Western Canada Sedimentary Basin has become non-core to the major companies.

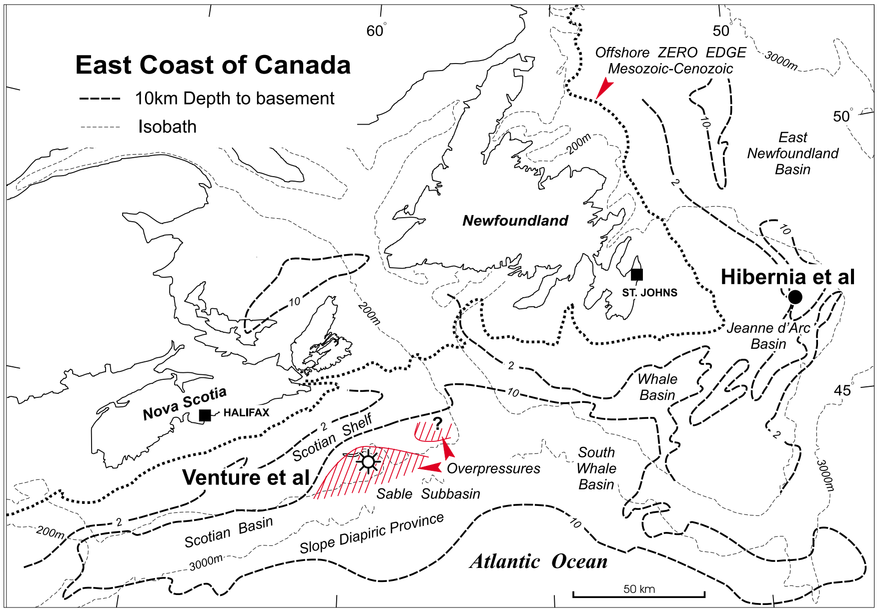

Figure 8 – East coast of Canada; Venture et al is the location of the Sable Offshore Energy Project; Hibernia et al includes the development at Hibernia, Terra Nova and others (e.g. Whiterose) in the Jeanne d'Arc Basin.

The conventional crude oil resource base for the Western Canada Sedimentary Basin is about 18 billion m^3 (113 billion barrels) of oil in-place, consisting of about 11.5 billion m^3 (72.5 billion barrels) of light oil and 6.5 billion m^3 (41 billion barrels) of heavy oil (NEB, 1999a). Light oil remaining established reserves are approximately 338 million m^3. Ultimate recoverable resources are about 3.6 billion m^3 (22 billion barrels) of light oil and 1.3 billion m^3 (8 billion barrels) of heavy oil. Undiscovered recoverable resources amounted to approximately 666 million m^3 (4.2 billion barrels) of light oil and 230 million m^3 (1.45 billion barrels) of heavy oil. (see also Bowers and Drummond, 1997).

Light crude production has been in decline for a considerable time and irrespective of new seismic and drilling technologies, that decline will not be arrested. Conventional light crude production will approximate $300 \times 10^3 m^3$ (1.9×10^6 bopd) on exit from 1999 and by 2010 the level will be further reduced to $234 \times 10^3 m^3$ (1.48×10^6 barrels) of oil per day (NEB, 1999a). Many of Alberta's traditional light oil producing pools produce with high water cuts and are tightly infilled with wells. Bowers et al, (1995) have reported on the benefits of horizontal drilling on the profitability of conventional crude oil production and increases in recovery and incremental supply to be expected in the basin (of the order of 450×10^6 m^3 or 2.8×10^9 barrels).

Heavy Oil

Most heavy oil production occurs from deposits in eastern Alberta and central Saskatchewan around Lloydminster. These deposits occur down-dip of and are the southern extension of the bituminous sands deposits of northern Alberta. The oils are typically lighter than the bitumen and some can be produced by conventional methods (e.g. with screw pumps) although recovery may be lower than those from more conventional light oil fields (see, for example, Johnson and McMillan, 1993, p.553-555). The reservoirs are complex multiple sand units of the Cretaceous Upper Mannville (e.g. Sparkey) at depths of 550 m. Porosity can be high (to 30%) with high permeability to several Darcies.

The National Energy Board (NEB 1999a) reports cumulative production (to end 1997) of 536 million cubic metres (3.3 billion barrels) with remaining established reserves and those attributed to future enhanced recovery (presumably including screw pump technology) 520 million cubic metres (3.3 billion barrels). Ultimate recoverable resources are 1285 cubic metres (8.1 billion barrels) of which approximately 42% has been produced. Original oil in-place figures are 6.575 billion cubic metres (41 billion barrels) of which, then, 19% is considered recoverable. Future demand for heavy oil (and bitumen) is assured for refinery feedstock (see Figure 3 after Imperial, 1999). A major impediment to greater investment in heavy oil production is price volatility such as was experienced in 1999.

Oil Sands

In 1998, total production from the oil sands was nearly 600,000 barrels per day, representing 27% of total Canadian crude oil production. Whereas light crude production from the Western Canada Sedimentary Basin is under rapid decline, its contribution and importance to supply is becoming of less importance. Heavy crude extraction and the production of upgraded crude from the mining of oilsands is rapidly increasing (see excellent recent summary by Singh, Du Pleissis, Isaacs, and Kerr, 1999). This is because the costs of producing upgraded crude oil from oil sands is now competitive with full-cycle conventional oil production costs, particularly in North America. The resource is also limitless, does not deplete for all practical purposes and there is a ready market.

Major oil sands deposits underlie about 77,000 km^2 (29,730 mi^2) of the province of Alberta (Figure 4). They occur in Cretaceous clastics and Devonian carbonates. (see Hills, 1974; Ranger and Pemberton, 1997; Stobl et al, 1997). Original bitumen in-place resources are reported as 1700 Billion Barrels or 268 million m^3 (Imperial, 1999a) of which about 9% (24 x $10^9 m^3$ or 152 million barrels) is amenable to surface mining and the remainder to in-situ thermal stimulation processes at depth. The bitumen extracted from oil sands is generally less than 12 degrees API with reservoir bitumen saturation levels from 1% to 18%. Upgraded product, for example, Syncrude Synthetic Sweet blend, is 31-33 degrees API crude containing less than 0.2 % sulphur and is comparable to Saudi Light. It sells for a premium to WTI.

The origin of the oil sands/heavy oils from most of the major Cretaceous deposits and the underlying carbonate trend has been the subject of much debate and geochemical analysis (see, Brooks, Fowler and MacQueen, 1988). To date, conclusions are that these oils have originated from a mature, conventional oil which was generated by an unknown source. In any event, the oil migrated over a vast distance, suffering biodegradation in place and during migration.

The deposits occur in three major areas, namely, Athabasca, Peace River and Cold Lake (Figure 4). The Athabasca deposit accounts for 76% of the total oil in place in the oilsands deposits, with the Peace River and Cold Lake deposits accounting equally for the remainder.

Athabasca

At Athabasca the bitumen bearing deposits are at mining depths (overburden <75m). These areas are the location of two current mining operations (Suncor, Syncrude) and others in an advanced planning stage (Shell's Muskeg). The mining involves stripping the overburden, which is saved for reclamation, and excavating the bitumen by mechanical shovel and truck, or by dredging. Where overburden thickness is prohibitive for surface mining, in situ, thermal mechanisms for the recovery of bitumen from oil sands deposits is attempted. To date, these oil sands have produced over 396 x $10^6 m^3$ (2.5 billion barrels – see Figure 5). Juxtaposed to the Athabasca tar sand deposit is the Upper Devonian Grosmont Formation in northeast

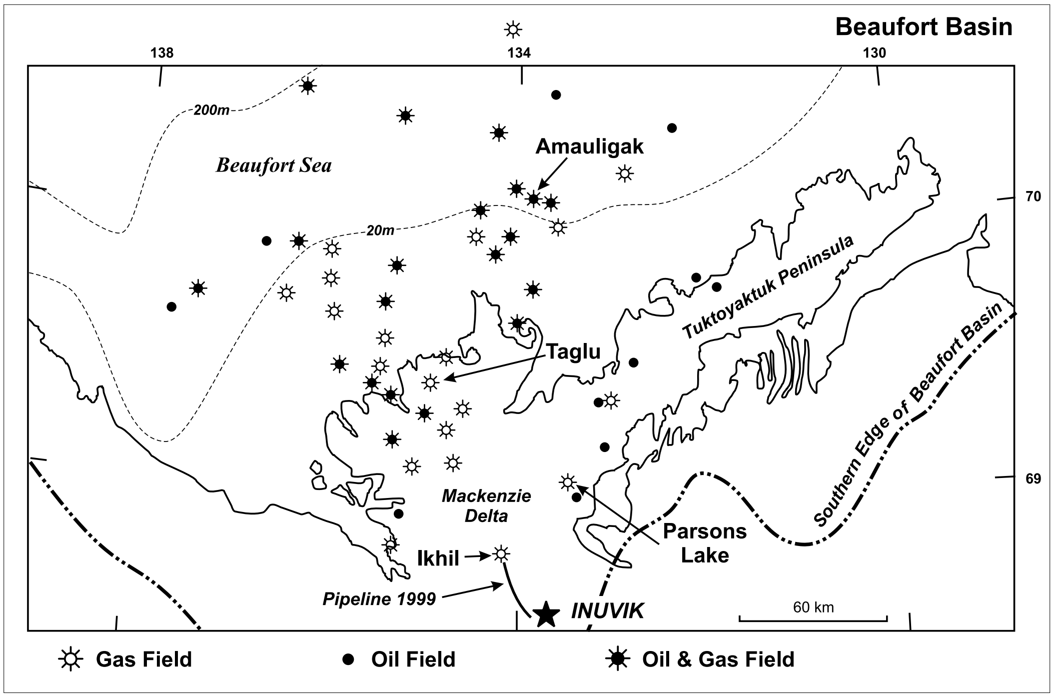

Figure 9 – Discoveries in the Beaufort Basin; classification after National Energy Board 1998; Amauligak is largest offshore oil discovery to date; Taglu and Parson's Lake (and others) should be part of overall future gas development scenario; the small Ikhil gasfield was commissioned to supply gas to Inuvik in 1999.

Alberta. The Grosmont Formation contains approximately 50 x 109m^3 (300 billion barrels) of 7^0 API heavy bitumen and represents a giant hydrocarbon deposit. Excepting three pilot sites that were operated for a few years in the 1980's, the Grosmont reservoir has not been exploited. At present, the Grosmont is under consideration for steam and / or CO_2 injection (see Luo, Machel and Shaw, 1994). If large sinkholes or caverns filled with bitumen were ever detected in the Grosmont, these would make interesting recovery points!

Peace River

The Peace River deposit comprises bitumen-rich sands from the Cretaceous Aptian-Albian Gething Formation, Ostracode Zone, and the Bluesky formation, which overlay Paleozoic and older Mesozoic strata. Exploitable reserves at Peace River are contained predominantly within the 15 – 20 m (50 – 65 ft) thick estuarine sands of the Bluesky formation. Where combined with the underlying fluviatile sands of the Ostracode Zone, net pay can reach 30m (100 ft) in thickness. These sands occur at depth of 550m (1800 ft) and production of the bitumen relies on non-conventional methods. Heavy oil (>10API) resources in place in the Bluesky-Gething interval are estimated at almost 90 billion barrels (14 X10^{9}m^3). Approximately 2.2 x 10^9 m^3 (13.8 x 10^9 barrels) are considered to be recoverable (Singh at al, 1999). Cyclic steam stimulation, or CSS (see later) and Steam Assisted Gravity Drainage, or SAGD (see later) are the usual methods to extract the bitumen, which reaches saturations of up to 88% in sandstones with porosity to 28% (Hubbard, Pemberton, Howard, 1999).

Cold Lake

The Cold Lake oils sands deposits occur within the Lower Cretaceous Mannville Group covering 6,527 km^2

(2520 mi^2) in northeastern Alberta. Reservoir units attain thickness in excess of 70 m (21 ft) at depths of 400m (1313 ft) – 500 m (1640 ft). Typical resource values are 15 x $10^6 m^3$ (100 x 10^6 barrels) of oil –in –place per square mile. Cyclic steam stimulation (or CSS) is expected to result in recovery factors of 25% to 30% in better-quality reservoir areas.

Surface Overburden removal and Mining at Athabasca

The Lower Cretaceous McMurray / Wabiskaw stratigraphic interval contains approximately 143 x 10^9 m^3 (902 billion barrels) of bitumen in the Athabasca Oil Sands area, northeastern Alberta, north of Ft McMurray. Of this about 24 x$10^9 m^3$ (152 billion barrels) occurs at mineable depths (overburden less than 50 feet) (Wightman and Pemberton, 1997; see also Flach, 1984).

Two major mining enterprises Suncor, (formerly Great Canadian Oil Sands – the world's first integrated oil sands mining and upgrading plant which commenced in 1967-see Suncor, 1999) and Syncrude Canada, are actively mining and upgrading the local bitumen near Fort McMurray. Syncrude Canada, on-stream since 1978, is the largest operator and currently produces 12% of Canada's light crude oil and manufactures over 34,900 m^3 (220,000 barrels) of upgraded or synthetic crude per day. During 1998, it produced its billionth barrel. Suncor produces approximately 16,600 m^3 (105,000 barrels) oil per day on an annualized basis.

Through the period post 1986, significant progress has been made in the cost of extraction such that today the mines of Syncrude and Suncor have production and operating costs of approximately US$ 8.0 per barrel (see Figure 6). Changes in mining machinery, with large draglines replaced by mobile truck and shovel operations, are allowing more confidence in large-scale investment in additional oilsands plants. About 2 tonnes of oil sands is required to produce one barrel of light, sweet, synthetic (upgraded) crude oil.

Additional investment is being made in upgrader capability and it is projected that over 50% of Canadian liquids production will come from the oilsands by 2015. Issues, which effect the mining of oil sands, include:
(a) environmental issues, including "greenhouse gas" emissions and CO_2 sequestration, and reclamation, particularly of tailings ponds.
(b) adequate supply of diluent.
(c) price of natural gas used as fuel.
(d) massive front end investment requirements to take advantage of "economies of scale".

The product produced is not a major hurdle; today Syncrude makes nine products and can supply tailor-made feedstock for refineries.

In situ recovery

In situ thermal recovery processes includes Steam Assisted Gravity Drainage (SAGD) technology and Cyclic Steam Stimulation (CSS). SAGD uses parallel horizontal injector and producer wells. Steam is injected into the oil-bearing formation via an upper horizontal wellbore to create a "steam chamber" which progressively heats the oil. It is desirable to achieve a pressure increase in the formation that approaches the fracture gradient. The oil's viscosity is reduced such that the oil flows by gravity down towards the lower horizontal wellbore which acts as the collection point. The oil is pumped to surface (Figure 7). Typical rates for well pairs are $100m^3 / d$ (600 bopd). Various combinations of horizontal well configurations are being evaluated to maximize recoveries. (SAGD) is undergoing testing by several companies in Athabasca and Cold Lake with promising results but a large-scale commercial plant has yet to be announced. Typical of in-situ potentially com-

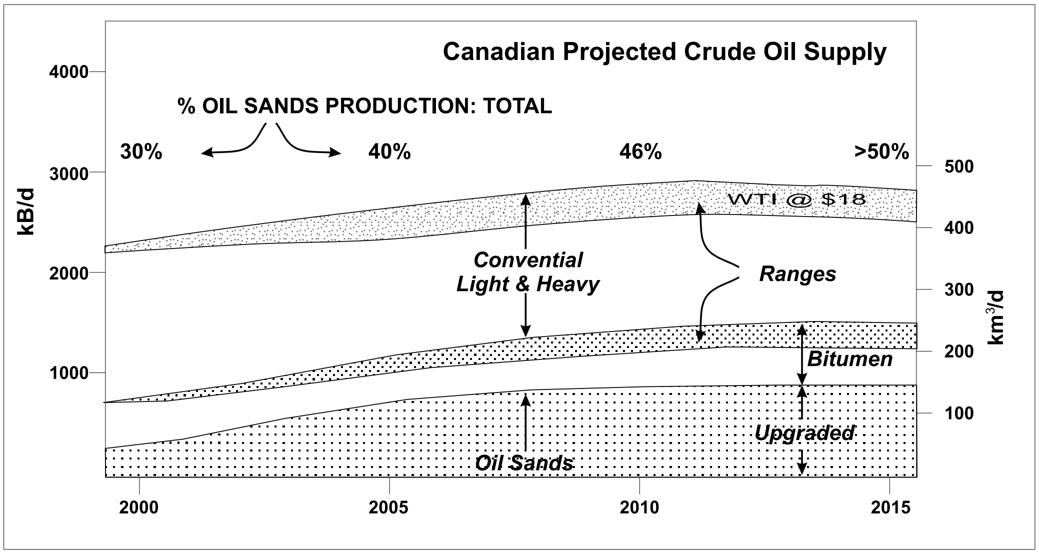

Figure 10 – Projected crude oil supply in Canada to 2015. Note the importance of oilsands production (data modified from NEB, 1999a).

mercial SAGD projects is the proposal by PanCanadian at Christina Lake, 130 km (81 mi) northeast of Lac La Biche. The project is to develop an area of 20.7 km^2 (8 mi^2) to produce between 8,000-11,000m^3/d (50,000 and 70,000 barrels per day) of crude bitumen from the McMurray formation by 2005 through three phases of development.

Cyclic Steam Stimulation (CSS) is predominantly a vertical well process, with each well alternately injecting steam and producing bitumen and steam condensate. A heated zone is created whereby the bitumen can flow back to the well. Imperial Oil's Cold Lake project is the major proponent of CSS and is the flagship of in situ projects. Cold Lake is projected to produce over 23,800 m^3 (150,000 barrels) of bitumen a day early in the next decade (see Imperial, 1999b).

Other technological developments are on the horizon including the Vapex process where solvents are recycled and reused. Significant cost reductions over SAGD may be possible.

Oilsands summary

Multiple projects will pump C$30 billion of investment into development of three oil sands regions of Alberta at Cold Lake, Peace River and Athabasca. Of this, C$25 billion is targeted at the Athbasca area alone. Oilsands production at is projected to rise to 50% of Canadian and 10% of North American crude production within the next 10 years. 'A solid oil sands industry base is in place today, including infrastructure, production facilities and organizations, as well as technology and know-how.' (Dingle, 1999b). For the Canadian petroleum industry, the intent is to more than offset the decline in conventional liquids production by increased non-conventional production, primarily through growth in cost efficient mining projects and in-situ thermal stimulation projects.

The Western Canada Sedimentary Basin north of Latitude 60^{o}: NWT (Mackenzie Valley) and Yukon

Vast areas of the NWT are only lightly explored. Excluding the Mackenzie Delta, approximately 500 exploratory wells have been drilled seeking mainly Paleozoic clastic (Cambrian) and carbonate (Devonian, Mississippian) reservoirs and, in the southern Territories, Mesozoic (Cretaceous) sandstone reservoirs.

The NWT has five regions with hydrocarbon potential: the Southern territories (up to 64 degrees N latitude) the Mackenzie Plain, the Peel plateau, Colville Hills, and the Mackenzie delta region (Bird et al, 1995). Yukon potential is limited to the Whitehorse trough, the Liard Plateau and Eagle Plain Basin (for Eagle plain basin, see assessment YGT, 1994b; Davidson et al, 1995). To date, most of the significant discoveries in the north are located throughout the western part of the NWT, within the northern part of the Western Canada Sedimentary Basin and in the extreme southeast portion of the Yukon along the Liard Plateau (YGT, 1994a; see also NEB, 1996; Price 1995). Dixon and Stasiuk, (1998) have summarized the hydrocarbon potential of Cambrian ("Tedji Lake") plays in the interior plains (Colville Hills) east and northeast of Norman Wells.

In the Mackenzie Valley, land issuance was under a moratorium between 1979 and 1994 due to the recommendations of the Berger Commission and unsettled Aboriginal land claims. Hence, even though some of the exploration plays pursued in Alberta and British Columbia which extend into the Northwest Territories (NWT), there has been much less exploration than in those provinces. Following the settling of Aboriginal land claims, the issuance of exploration rights recommenced in the Beaufort in 1989, the high Arctic in 1991 and in the NWT in 1994 (Morrell et al, 1995).

Gas production takes place at Pointed Mountain (mainly depleted but to be replaced with production from recent gas discoveries at Liard). Oil production is limited to Norman Wells (for location see Figure 2). The Norman Wells field is located in the Northwest Territories on the Mackenzie River, just south of the Arctic Circle and produces approximately 4,400m^3/d or 28,000 bopd. Since 1985, the field has produced over 23.8 x $10^6 m^3$ (150 million barrels), which has been piped 864 km (540 mi) to connect to infrastructure in northern Alberta. Ultimate recovery may be 37.5 x $10^6 m^3$ (235 million barrels). Attempts to duplicate this discovery have been futile to date.

Remaining potential in the NWT will be vigorously persued once infrastructure is in place to the Mackenzie Delta but the resource potential is not considered large.

Basins on Canada's East Coast

Canada's East Coast basins (Scotian Shelf, Grand Banks, East Newfoundland Basins – excluding Labrador – see Figure 8) have a gas resource potential in excess of 1.7 x $10^{12} m^3$ (60 Tcf-see Drummond, 1998). Of this total, approximately 283 x $10^9 m^3$ (10 Tcf) has been located to date. The prime area for early exploitation and further exploration success is the Scotian Shelf – primarily because development is underway and operating conditions are within the technology envelope. Investment is cautiously proceeding in other more northerly areas along this margin as operators gain confidence, comfort and experience in harsher conditions. Exploration enthusiasm remains high for Canada's east coast basins, mainly on the Scotian Shelf off Nova Scotia and in the Jeanne d'Arc basin, on the Grand banks, offshore Newfoundland (see Newfoundland Ocean Industries Association, 1998). Recent exploration commitments will cause the expenditure of over C$1.0 billion on new seismic and drilling in these areas over the next 5 years. New discoveries are imminent. Bell and Campbell (1990) summarised the three main areas of interest for significant petroleum resources in Mesozoic basins along Canada's East Coast margin. These areas are: the Scotian Shelf and Slope off Nova Scotia, the Grand Banks of Newfoundland (Jeanne d'Arc Basin) and the Labrador Shelf (Hopedale and Saglek Basins). (see also, Grant, McAlpine, Wade, 1986; Meneley, 1986, Balkwill et al, 1990, Wade and MacLean, 1990).

Williams and Grant (1998) have published the latest definitive tectonic assemblages map of the coastal region of Atlantic Canada. Rifting between North America and Africa began in Late Triassic resulted in a rifted margin off Nova Scotia and a transform margin south of Grand Banks. Seafloor spreading, thereafter, produced Jurassic and Cretaceous oceanic crust south of the Grand Banks. Stretching and rifting of the crust between North and Greenland began in Early Cretaceous accompanied by fault troughs, some of which contain Cretaceous sediments, in the region surrounding the Labrador sea and Baffin Bay. East-northeast seafloor spreading in Labrador Sea began in late Cretaceous time but changed to north-northeast in early Eocene. Seafloor spreading started in Baffin Bay in the latest Cretaceous or Paleocene, but ceased in both Baffin Bay and the Labrador Sea in the Late Eocene. Seafloor spreading continued during the Cretaceous and Cenozoic in the North Atlantic, where the Mid – Atlantic Ridge remains an active spreading center today (Geological Map of Canada, 1999).

Basins off Nova Scotia - Scotian Shelf

The Scotian basin (Province Code 5217, USGS, 1997) is located beneath the outer part of the Scotian Shelf, offshore Nova Scotia (Atlantic Geoscience Centre, 1991 and see Figure 8). The basin exhibits all the features of a classic passive margin: early rift deposits, a wide mantle of evaporites, carbonate platforms, giant prograding wedges of clastic sediments, salt diapirism, overpressuring, hydrocarbon generation and entrapment, extensional faulting and basinward tilting of postrift sediments. Beneath the continental shelf the basement is faulted into a series of horsts and grabens. Locally they are filled with Upper Triassic- lower Jurassic synrift clastics. Overpressuring is present (Yassir and Bell, 1994, Drummond, 1992) and is of such severity that fracture gradients may be exceeded allowing for leakage and secondary migration of petroleum into shallow, normally pressured intervals. In the Venture field, discovered in 1979, gas occurs in multiple sandstone reservoirs, from Upper Jurassic to Lower Cretaceous age, over a stratigraphic interval of 1600m (5250 ft) (Drummond, 1992). The majority of accumulations discovered to date are restricted to clastic reservoir intervals in Late Jurassic to Late Cretaceous sediments.

The source rock for the gas discoveries on the Scotian Shelf is the Upper Jurassic-Lower Cretaceous Mic Mac (Verrill Canyon Formation) shales. The majority of gas discoveries to date appear to occur proximal to the western (updip) limit of the geochemically mature interval. Petroleum maturation and migration has occurred since mid Tertiary time. There appears to be adequate evidence for secondary migration with shallower reservoirs containing early-generated hydrocarbons displaced from depth by later maturation products. Traps are dominated by growth- faulted rollover anticlines although compaction drape features over salt pillows and other lithologies do occur.

Wade et al (1989) concluded the median expectation for gas resources was 512 x $10^9 m^3$ (14.5 Tcf), the Canadian Gas Potential Committee (Canadian Gas Potential Committee, 1997) estimated marketable gas potential at 455 x $10^9 m^3$ (12.9 Tcf) whereas the NEB (1998) reported an ultimate marketable resource figure of 635 x $10^9 m^3$ (18 Tcf). The largest discovery to date is Venture D-23 (Canadian Gas Potential Committee, 1997) at 59.5 x $10^9 m^3$ (2.1 Tcf) gas in place and it is considered unlikely any larger accumulation will be discovered in the Sable Subbasin. Discoveries of this size in deeper water will not be attractive stand-alone development candidates (see Canada-Nova Scotia Offshore Petroleum Board, 1997).

The East Coast is an area of significant growth potential. It offers a large resource base, a developing infrastructure and proximity to large and growing gas markets in the Maritimes and northeastern U.S. Oil potential is considered insignificant for the purposes here. Verification of the presence of mature oil prone source rocks is a prerequisite for charging potential new play concepts.

Basins off Newfoundland - Grand Banks

The Grand Banks basins (see Province Code 5215, USGS, 1997) cover an area of approximately 330,000 km^2.

The water depths are relatively shallow at between 60 – 300 meters (200-1000 ft). Approximately 115 exploration wells have been drilled in this area, 69 or 60% drilled in Jeanne d'Arc Basin (Bruce, 1999). With the discovery of 17 fields containing 254 x 10^9m^3 (1.6 billion barrels) of recoverable oil and 113 X 10^9m^3 (4 Tcf) (Canada-Newfoundland Offshore Petroleum Board, 1999; Bell and Campbell 1990; Grant and McAlpine, 1990). The Flemish Pass, east Newfoundland, Whale, Horseshoe and Carson basins are largely unexplored. The physical environment is similar to the North Sea except for the presence of icebergs in April to July and sea ice in the winter.

Reserve base is large with significant discovered pools. Hibernia and Terra Nova are the largest accumulations of conventional oil remaining in Canada today. Reservoir quality is good such that wells have high productivity. During 1998, the Hibernia B-16-1 well set a Canadian daily flow record when it tested 56,000 barrels of oil per day.

The development of suitable stand-alone production facilities such as those at Hibernia and planned for Terra Nova, White Rose, possibly Hebron/Ben Nevis and Riverhead would be able to process reserves produced from satellite fields within 15 kilometers.(Sinclair et al, 1992, Taylor et al 1991).

Jeanne d'Arc Basin

The Jeanne d'Arc Basin represents a Mesozoic, failed-rift basin containing more than 20 km (65,000 ft) of sedimentary fill. Sediments range from Triassic to Tertiary. An overpressured zone occurs below approximately 4 km (15,200 ft) and is concentrated mainly in Jurassic sediments. (Rogers and Yassir, 1993). The overpressuring is possibly related to oil generation in the Jurassic source intervals, mainly the Egret Member shales (Kimmeridgian) which contain oil prone (Type II) kerogens. (Williamson, Des Roches and King, 1993). The Egret is recognized as a "world class" oil source. The unit ranges in thickness from 55m (180 ft) to in excess of 200m (656 ft). Peak generation occurred in the Early Tertiary (50MBP) and post dates early traps. Fowler and McAlpine, (1995) suggested, based on mass balance and hydrogen index techniques that perhaps 39 $x10^9m^3$ (245 billion barrels) of oil has been generated from the Egret Member. If only 10% was captured in reservoirs and 30% were recoverable, this would give an exploration target of 1.2 x 10^9m^3 (8 billion barrels) of oil; 75% more than located to date. It seems appropriate to refer to the Egret-Hibernia(!) and Egret-Avalon(!) petroleum system when referring to the Jeanne d'Arc since Egret sourced oil is trapped in reservoirs of the Cretaceous Berriasian- to Valanginian-aged Hibernia sandstones at depths of 3,700m (12,136 feet) and Cretaceous Barremian- to Albian age Avalon sandstones at depths of 2,400m (7,872 feet) in Hibernia field (Mackay and Tankard, 1990, Hurley et al, 1992).

Petroleum resources of the Jeanne d'Arc basin may only be lightly tapped to date but other Mesozoic basins off Newfoundland are considered to have limited potential for additional light crude reserves considering the logistical difficulties of developing fields. Estimates of potential economic resources and technically recoverable oil are of the magnitude of an additional 476 x 10^6m^3 (3 billion barrels) to 634 x 10^6m^3 (4 billion barrels) over the reserves in Hibernia (estimated at 120 million cubic metres or 750 million barrels recoverable by Mobil) and Terra Nova (58 – 92 x 10^6m^3 or 370-580 million barrels recoverable). Extrapolations of gas potential have been published but up to 283 x 10^9m^3 (10 Tcf) recoverable might be possible. Beyond these numbers, projections may be meaningless as the comfort and experience to develop these kinds of reserves off Newfoundland must await offtake mechanisms at Hibernia and White Rose. Subject to a declaration of commerciality, White Rose is scheduled on stream 2002-2004.

Some observers feel the jury is still out on whether the development of these resources is economically justified. In addition to the hostile environment, variations in crude gravity, geological complexity of some reservoirs, and areal coverage of some fields has made the decision to invest difficult. A major challenge for the

Grand Banks area is the production of associated and potentially non-associated natural gas. On an individual project basis, gas is available in less than commercial volumes (Wagner, 1999). Options for developments include compressed natural gas, liquefied natural gas and gas-to- liquids conversion. Several players are looking at compressed coselle technology. Each coselle – coiled pipe in a carousel-shaped container – can store about 3.1 mmcf and 108 in one ship could store 330 mmcf of compressed gas. A pipeline alternative will require large volumes of natural gas to be available and threshold volumes have yet to be proved. Unless very large features (capable of containing stand-alone resources) are mapped on seismic, explorers will be reluctant to drill if there is a gas risk. Costs for a buried pipeline from the Jeanne d'Arc Basin to Nova Scotia, with a crossing of the Laurentian Channel, will be costly. However, if large volumes of gas are stranded following further successful exploration over the coming decade, the pipeline option to the large US market will become a serious project.

Basins off Labrador

Gas discoveries were made initially off Labrador in the early 1980's (Atlantic Geoscience Center, 1989; Balkwill et al, 1990). The most significant accumulation discovered is at Bjarni with over 2.23 Tcf (63.3 x $10^9 m^3$) marketable gas reserves (this reserve estimate is larger than that in any other gas field discovered to date on the East Coast e.g Scotian Shelf). The gas is trapped in Lower Cretaceous clastic reservoirs; the gas probably sourced from interformational coals and lignites.

Estimated threshold reserves to interest investment, with adequate per well productivities, may be of the order of 170 x $10^9 m^3$ (6Tcf). The appetite for additional exploration over the next 20 years is not evident and we consider these resources to be orphaned within any present forecast span. Total known resources in several scattered fields are approximately 141 x $10^9 m^3$ (5 Tcf). This is not a large accessible resource versus some other areas of North America.

Key elements affecting the attainment of threshold reserves for marketing are:

(a) geological risk-results to date have not established major natural gas (or oil) deposits adequate to entice stand-alone development.

(b) ice management – the area is a major thoroughfare for the movement of icebergs south along the Labrador offshore margin; scouring of the seabed by large icebergs poses a risk for pipeline connections and subsea wellheads.

(c) geotechnical elements – the seabed is littered with boulder fields produced by the melting of rafted material which historically have caused difficulties in the drilling of conductor holes for offshore wells and the placing of protected subsea wellheads.

(d) distance from markets, market needs and hence adequate commodity price to provide a reasonable netback.

(e) well costs and the limited drilling and construction windows.

The industry needs to achieve a high degree of comfort with the operating conditions further south, particularly on the Grand Banks, to take much interest in the known and potential gas resources off Labrador. This might occur when the more accessible resources off Nova Scotia and Grand Banks are determined to be inadequate to service northeastern US markets. Since it is unlikely that the petroleum industry will show much interest in additional exploration to garner threshold reserves to initiate a gas production project off Labrador, the resources will clearly remain stranded and orphaned well into the next century.

East Coast Basins Future Potential

The discovery of new oil reserves in unproven East Coast basins really relies on the extrapolation and discovery of world class source rocks such as the Jurassic Egret Member. There are basins on the Grand Banks where early shows might indicate the presence of potential Jurassic source, e.g. Whale Basin.

Oil potential off Nova Scotia remains a long shot since there has been no encouragement that a significant oil source is preserved beneath the Scotian Shelf. Anoxic conditions or restricted circulation was not a characteristic of either late Jurassic or Cretaceous paleogeography particularly off the Nova Scotia margin. Tertiary clastic wedges appear to be dominated, as expected, with terriginous material suitable only as a potential source of gas or wet gas and condensate.

Exploration permits have recently been awarded off Nova Scotia into water depths of 2,000m (6500 ft). There is considerable interest in the potential for the discovery of giant gas fields in the zone of assumed (Triassic Argo) salt diapirs ("Slope Diapiric Province" in Wade and MacLean, 1990, p.200 Figure 5.23) which occurs along and beyond the break in slope of the Scotian Shelf. For supra-salt plays the major reservoir objective must be in the Tertiary and ?Upper Cretaceous. Low stand wedges in the Tertiary would be a topical play, but hydrocarbon charge and the ubiquitous presence of good quality reservoirs might be an issue. High heat transfer due to the presence of salt and features produced by halokinesis (or ?lutokinesis) should bode well for maturation if suitable source intervals were present and speculative source rocks are buried to suitable depths. There is no doubt that large salt related roll-over prospects are present but they might exist in considerable depths of water (up to 2000m or 6500 ft). Ponded resedimented clastic facies are possible between diapiric swales (stratigraphic and "structural-stratigraphic assist" pinchout plays) but no direct hard data is available to the author to substantiate this possibility.

Exploration is now being conducted in the previously declared St. Pierre Moratorium Block south of the French islands of St. Pierre and Miquelon (off the southern coast of Newfoundland). The Laurentian Subbasin is a deep Mesozoic extension of the Scotian Basin. MacLean and Wade (1992) assessed the area as having similar potential to other areas off Nova Scotia since evidence for good Jurassic (or other) oil source was not present. Over 300 leads were identified and based on parameters similar to the Sable Island "model", average expectation was for the discovery of 255 x $10^9 m^3$ (9Tcf) and 15.8 x $10^6 m^3$ (100 million barrels) of liquids. Areal sizes of leads (and/or stacked pays), reservoir properties and fluid contents will be major considerations for pre-drill decisions and the potential for commercial development. Mesozoic prospects, on the updip margin of the Laurentian Basin against the Burin Platform (in water depths to 200m or 600 ft), would be of interest.

Tertiary wedge edge plays are an exploration target and the influx of mass flow ("resedimented") sands might be possible (Batemen et al, 1999) associated with, for example, the Tertiary Oligocene low–stand. This event is pervasive elsewhere along the Labrador and North Atlantic margins. Charging these plays with hydrocarbons sourced from mature older startigraphic intervals, may pose a challenge.

The sizes of gas fields discovered to date are not large by world standards but the area is within reach of a large continental market. If gas finds to date are typical of the of the size of fields yet-to-be-found, and these new discoveries occur in deeper waters, then, without higher gas prices, they will lie dormant for some considerable time. Discoveries in the deeper waters off the Scotian Shelf, may need to exceed 5 Tcf to be attractive for stand-alone development. The requirement of thick pays and high productivity wells is also present. It is unlikely this area will drive the technology required to develop a group of smaller fields in water depths greater than, say, 1,500m (4,950 ft).

BASINS NORTH OF THE ARCTIC CIRCLE

Mackenzie Delta

Natural gas and oil from the Beaufort-Mackenzie Basin (Province Code 5239, USGS, 1997) is hosted in high productivity Tertiary and Cretaceous sandstone reservoirs (see Dixon, 1995, Lane and Dietrich, 1995). Over 200 wells have been drilled in the Beaufort Basin since 1965. There are presently 62 discoveries held under Significant Discovery Licenses (RWED, 1999; see Figure 9). The largest discovery of gas to date in the Mackenzie Delta is the Taglu Field (see Figure 10), discovered by Imperial Oil Limited in 1971 (see Tsang, 1990). Estimated mean marketable reserves in the Taglu field are 58.6 $X10^9m^3$ (2.1 Tcf), in Parson's Lake, 35.4 $x10^9m^3$ (1.25 Tcf) and Niglintgak 13.6 $x10^9m^3$ (480 Bcf). In the Beaufort Sea, Amauligak is the largest oil and gas (associated) discovery with mean recoverable oil of 37.3 x 10^6m^3 (235 million barrels) and mean marketable gas of 38.5 $x10^9m^3$ (1.3 Tcf), (NEB, 1998).

Dixon et al (1992) estimated the Eocene (Taglu sequence) and Oligocene (Kugmallit sequence) contain recoverable resources estimated at 542 x 10^6m^3 of oil (3.4 billion barrels) and 1037 x 10^9m^3 of gas (37 Tcf). These resources, and others, have in all likelihood, been sourced from a common Eocene source (Richards Formation).

Development of Mackenzie Delta gas reserves faces significant economic and technical challenges, primarily because of the large distance (843 mi or 1,350 km) of these reserves from existing infrastructure. So long as lower "supply-cost" gas exists near infrastructure, the economics of Mackenzie Delta gas development remain challenging. Recent awards of exploration permits in this area (Northern Oil and Gas Directorate, 1999) and upcoming drilling activities, optimistically view a declaration of commerciality before 2005, with an in-service pipeline constructed by 2008. This will depend on: (a) the proving up of threshold reserves, (b) higher gas price netbacks and (c) reasonable transportation costs (tolls) to tie into the extended infrastructure from the northern reaches of the Western Canada Sedimentary Basin and (d) co-operation among producers, pipeline companies and local communities. Since the early discovery of these resources, the advent of extended (and long-) reach and horizontal drilling will play a part in their ultimate development. These technologies will provide the ability to use smaller "footprints" in this environmentally sensitive area to access separate pools.

The delta area and the shallow waters of the Beaufort Sea (south of the southern limit of permanent sea ice) seems to have limited light oil potential for commercial development. The biggest discovery to date is Amauligak (1984 - see above) Most researchers consider the total recoverable oil discovered to date to be a modest 161 X 10^6m^3 (1.0 billion barrels). The potential might exceed 800 x 10^6m^3 (say, 5 billion barrels). These kinds of resources, if scattered through several "small" pools, will not be attractive to develop based on present price trends or competitively priced upgraded crude oil produced from oilsands. During the recent National Energy Board consultations, there was no interest indicated in oil production from the Mackenzie-Beaufort before 2025 (NEB, 1999a). Perhaps, once natural gas thresholds are exceeded and additional oil is discovered, oil resources may be co-mingled in a condensate line from the Delta area to Norman Wells. However, this does not look like an early (pre - 2025) possibility. Development of Beaufort Sea discoveries in shallow water (< 20m or 60 ft) may involve dry (buried) subsea completions, development pads built on artificial islands, or steel or concrete monocones designed to withstand the pressures of sea ice.

NEB (1998) estimates 255 X10 $^9m^3$ (9 Tcf) of marketable natural gas has been discovered and 1.56 x $10^{12}m^3$ (55 Tcf) of undiscovered gas resources remain. Threshold reserves for a pipeline tie-in are likely to be proven initially in the vicinity of Taglu and associated fields within a 50 km radius. Initial design suggests an high-pressure pipeline with capacity of 65 x 10^6m^3/d (2.33 Bcf/d) will be required for economic thresholds to be exceeded. A separate 12-inch natural gas liquids pipeline for natural gas liquids (NGL's) and condensate connected to the existing Enbridge system via Norman Wells would be viable. Gas throughput volumes of this magnitude suggests threshold gas reserves approaching 566 x $10^9 m^3$ (20Tcf) will be needed before there will be a commitment to construct a natural gas 'export" line.

The challenge of meeting sufficient reserves for pipeline commitment is not an easy one. The analysis by the Canadian Gas Potential Committee (1997) indicated from their projections (say ibid, Figure 12.6) that, perhaps, over 30 new fields each with marketable reserves of more than 8.5 x $10^9 m^3$ (300 Bcf) would be needed. This is a formidable investment which may take some time to assemble. For the first time in 8 years, new awards were made in 1999 for additional exploration in the Delta (see Northern Oil and Gas Directorate, 1999). Most NEB projections, done in consultation with industry, indicate Mackenzie Delta gas may not reach southern markets until after 2015.

Access to Alaskan gas resources on the North Slope, in conjunction with gas from the Mackenzie Delta, could possibly accelerate the construction of an "export" pipeline which would connect these two important future suppliers of natural gas to the Alberta and North American gas grid.

Key issues are:
(a) the participation of local communities and native peoples.
(b) threshold volumes for commercial development of natural gas.
(c) the associated liquids production will "piggy-back" natural gas development.
(d) price issues including sustained prices and demand over the longer term to justify investment in facilities and wells.
(e) construction costs.
(f) pipeline tolls.
(g) environmental solutions.

Arctic Islands – Sverdrup Basin

The Sverdrup basin (Province Code 5234, USGS, 1997) is situated in the Arctic islands in polar latitudes between 76^O N and 80^O N. The Sverdrup is an early Carboniferous to Tertiary basin. Extensional faulting affected its early history while compressional tectonics in Late Cretaceous to Oligocene time impressed a westerly diminishing structural grain on the area.

Much of the offshore area is prone to permanent sea ice but has been well explored during the late 1960's to the mid 1980's. Over 176 exploratory wells and approximately 120,000 km of reflection (2D) seismic data have been recorded (Geological Survey of Canada, 1995). There are 19 significant discoveries (held under Significant Discovery Licences of SDL's – see RWED, 1999). The largest field and the first significant gas discovery in the Canadian Arctic Islands is Drake Point (Waylett, 1990), an anticlinal trap discovered in 1969 on the Sabine Peninsula of Melville Island within the Sverdrup Basin. The field has estimated discovered marketable gas reserves of 150 X $10^9 m^3$ (5.3 Tcf) with potential of "reserve creep" to beyond 170 X $10^9 m^3$ (6 Tcf). The dry gas is reservoired in Jurassic sandstones with beach (barrier bar) affinities. Middle Triassic to Middle Jurassic shales are contenders for the source of the gas. Characteristics of the field include 180m (600 feet) gas column and an areal extent of 436 sq km (168 sq mi or 100,000 acres). Of the total discovered initial volumes in place are approximately 566 x $10^9 m^3$ (20 Tcf), there are 15 discovered fields each with over 100 Bcf in place. Of significance, is that within 100 km (63 mi) of the Drake Point, there is approximately 10 Tcf of discovered marketable gas which is situated 1280 km (800 mi) from the Mackenzie delta (see, for example, Canadian Gas Potential Committee, 1997, p.78, and figure 12.8).

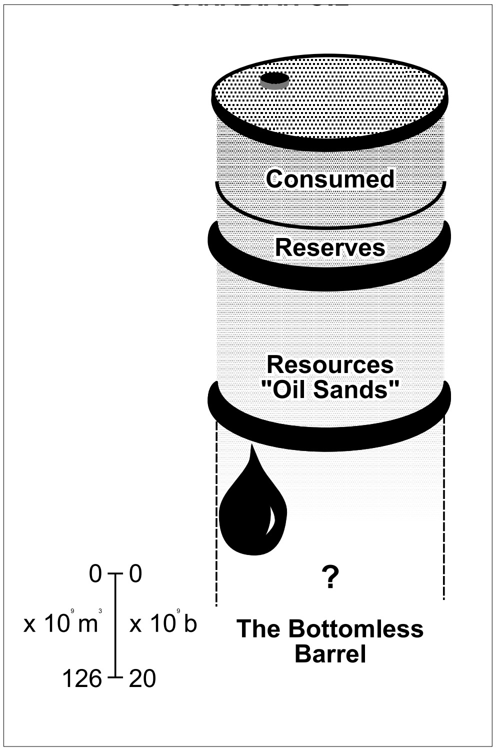

Figure 11 – Canadian oil; to highlight the large resource base captured in the oilsands – accessible mining resources alone can support the projected production rate of 1.5 million barrels per day for well over 100 years.

Marketable natural gas reserves are estimated to be 566 X $10^9 m^3$ (20 Tcf) (Canadian Gas Potential Committee, 1997) and "in place" oil resources are estimated at 254 x $10^6 m^3$ (600 million barrels) (Waylett, 1990). Reservoirs found to date are mainly sandstones of the Jurassic, Triassic and Early Cretaceous age. The Bent Horn oil field, which produced for a number of years from a single well (ceased 1997) by Panarctic Oils, has a small oil reserve in a Devonian bioherm (see Meyerhoff, 1982). A major source rock for the oil and gas discoveries in the Sverdrup basin are the bituminous ("anoxic") shales of the Schei Point group (Triassic) which have an average 4% TOC of marine Type II algal origin. Multiple phases of migration have caused mixed oil and gas accumulations (Waylett and Embry, 1992).

Early optimism for the development of such stranded reserves by ice designed vessels (gas carriers) transporting gas through the Northwest Passage has faded (see Couper, 1983, p.148). Feasibility studies for liquefied natural gas terminals, particularly at Bridport Inlet, Melville Inland, have been conducted (see Lewis and Keen, 1990, p.758). Pipeline options are probably favored. Indeed, research on the construction of such a pipeline has been conducted, with trenching from Drake Point to Bathurst Island with connection to the Boothia Peninsiula thence overland to markets in Ontario, Quebec and the US (see Strain in Clark et al, 1997, p. 227). In any event, all momentum and enthusiasm for Arctic Islands investment has waned and it is highly probable these resources will remain "stranded and orphaned" well beyond the present generation or any current "forecast span". Any estimated resources should therefore be deleted from current assessments of the Canadian marketable natural gas resource base. The principle problems are those of logistics, environmental protection, great expense, and the limited drilling season. For the foreseeable future, these are not attractive investment areas.

The potential of gas hydrates in the Canadian Arctic, although the subject of recent scientific research, are not discussed further here.

PETROLEUM POTENTIAL OF AREAS UNDER MORATORIA

West Coast Basins of British Columbia

These areas have been off limits since 1972. The Neogene and younger pacific margin is complex and variable. A convergent margin now exists west of Vancouver Island where the Juan de Fuca and Explorer plates are being subducted beneath the North American plate. A mainly transform margin extends from west of Queen Charlotte Islands to the submergent Yakutat Terraine in the Gulf of Alaska. Along this segment, the Pacific plate continues to move northward relative to North America along a dextral strike- slip fault. (Geological Map of Canada, 1999).

Major sedimentary basins of the Pacific margin of Canada are the Tofino Basin, the Queen Charlotte Basin and the Georgia Basin. These areas are considered to have the potential for 1.56 x 10^9 m^3 (9.8 x 10^9 barrels) of oil and 1.228 x 10^3 m^3 (43.4 Tcf) of gas (Hannigan et al, 1998). Dietrich (1995a, b) has detailed the petroleum resource potential of the Queen Charlotte basin, offshore British Columbia. Resource estimates are based on three conceptual plays involving Cretaceous and Neogene reservoirs (sandstone and conglomerates) and Jurassic and /or Tertiary source rocks. The Neogene plays of the Queen Charlotte Basin are considered the most prospective. Total recoverable resources are estimated at 414 x 10^6 m^3 (2.6 x 10^9 barrels) of oil and 565 x 10^9 m^3 (20Tcf) of gas at median values. These numbers appear overly optimistic based on earlier drilling results and the nature of the potential reservoirs, source and charge characteristics. In the event the moratorium on activities is lifted, a large 3D seismic effort combined with highgraded locations for exploration wells, will quickly indicate the overall prospectively.

East Coast - Georges Bank

The Georges Bank Basin underlies the central and western parts of Georges Bank and the adjacent slope (see Wade in Wade and MacLean, 1990, p171-190). The prospective area straddles the United States-Canada border. Wells have been drilled on the United States side without success but no wells have been drilled on the Canadian portion. Most of the oil and gas potential is likely to occur in the Middle Jurassic to Lower Cretaceous section, if any. Although under review, the Canadian ban on exploration activities is likely to be extended to 2012.

PROJECTED CANADIAN PETROLEUM RESOURCES

Projections of total marketable supplies of conventional natural gas from Canada are of the order of 200Tcf, based on recognized resources and extrapolation of play trends.

Projections of light conventional crude oil indicate very limited potential outside of the Beaufort Sea and the Grand Banks. Beaufort Sea projections hinge on the rank of the Amauligak discovery of only 300 million barrels, insufficient for an initial development. Grand Banks (Jeanne d'Arc Basin) assessments are encouraged by the rich Jurassic source rock (Egret) and the discoveries to date (Hibernia et al). Vast static resources await investment and extraction in the Alberta oil sands. Only 3 billion barrels is "booked" against current projects but the exploitable resource is well beyond 100 billion barrels.

CANADIAN PRODUCTIVE CAPACITY

According to most estimates, (e.g.NEB, 1999a), Canada is expected, at present production rates, to provide a

RESOURCES BY BASIN		
Basin:	($x10^{12}m^3$)	(Tcf)
Western Canada Sedimentary Basin	3.39	120+
NWT and Yukon (e.g. Liard plateau)	0.056	2
Scotian Shelf	0.509	18
Mackenzie Delta	1.41	50-
Grand Banks	0.283	10
Total	5.66	200

minimum of 4.2 x $10^{12}m^3$ (150 Tcf) marketable gas supplies during the next 20 years. Based on current assessments, one must assume these volumes will be produced from the Western Canada Sedimentary Basin (3.4 x $10^{12}m^3$ or 120 Tcf), which is about the same as all the gas produced to date, the Scotian Shelf (509 x 10^9m^3 or 18Tcf – a possible stretch target during the period) and the remainder from Alberta unconventional (coalbed methane, tight sands etc) or the Mackenzie delta (283 x 10^9m^3 or 10 Tcf). Based on the foregoing analyses, one must surmise a very different outlook in the year 2020 from that perceived today.

Projected crude oil supply from Canada (Figure 10) suggests a production rate approaching 480 x 10^3 m^3 (2.8 x 10^6 barrels) per day is attainable. Of note is the growing importance of production from oilsands with upgraded (synthetic) crude and bitumen exceeding 50% of total production by 2015.

Cost of Canadian Productive Capacity

Irrespective of how we view the extensive resource base in Canada (or elsewhere for that matter) or the magnitude of it various evaluators may agree upon, we must be aware of the cost of supply, the cost of production capacity and the limitations to the rate or intensity of investment in productive capacity. When viewed in a North American context, wellhead price increases for natural gas widens the resources that may be accessed at acceptable supply costs. These resources may be in abundance and once their exploitation commences, dampens price reducing the impetus for continued investment in resources with marginal economics. For oil, the large exploitable resources are the oil sands, where mining, handling and processing costs can now deliver a barrel of refined product at a very competitive supply cost. The accessible supply of oilsands is enormous but the rate and magnitude of investment will limit its production capacity (Figure 11). Much will remain orphaned and static well beyond any current forecast span. This (and favorable royalty and tax treatment for oilsands) will depress investment enthusiasm for remote exploration and development of oil discoveries in harsh, high cost Arctic locations. For example, extraction costs for Hibernia have been calculated at CDN $23.03 (USD 17.30) per barrel *as spent* on a 615 million barrel recoverable case (Hibernia, 1999). For Terra Nova (Terra Nova, 1999) capital costs as spent are C$4.5 billion and extraction costs (including operating costs) are USD 7.50 per barrel. These figures compare to CDN12.00 (USD 9.00) per barrel for upgraded crude oil from oil sands mining.

DISCUSSION

Canada is blessed with substantial petroleum resources such that *"the resource base is not in crisis"* (Kirk

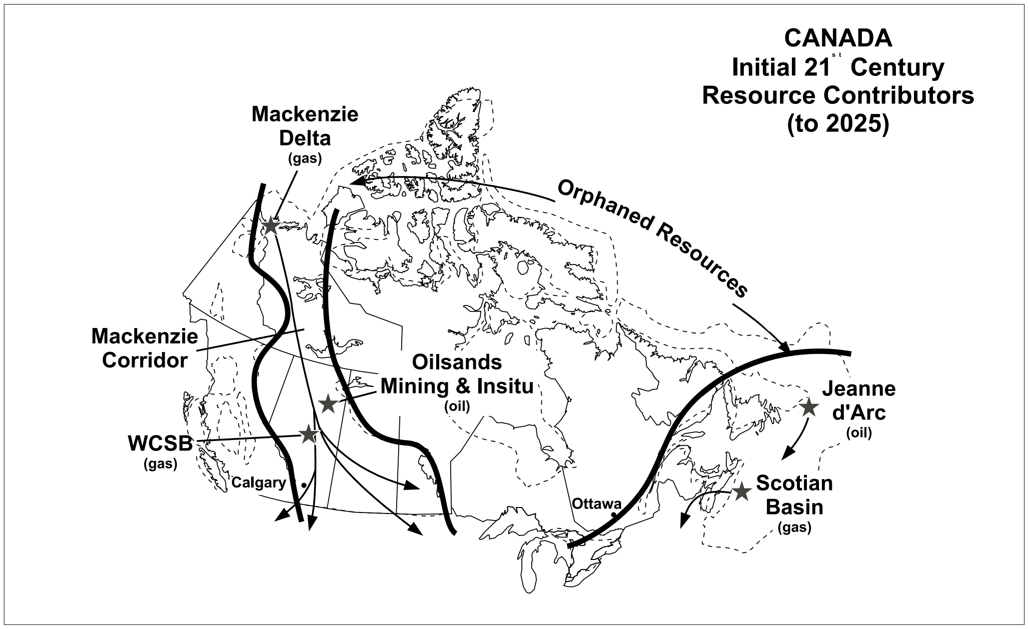

Figure 12 – Initial resource contributors of Canada in the 21st century; continued importance of the Western Canada Sedimentary basin (WSCB), the oilsands, increasing production from the Scotian and Jeanne d'Arc Basins and the development of the resources of the Mackenzie Delta.

Osadetz, personal communication 1998). Maintaining cost effective and competitively priced productive capacity for natural gas, conventional light oil, upgraded (synthetic) oil, in-situ bitumen production and heavy oil poses a serious challenge to alternative sources of hydrocarbons, for example, tight gas, coalbed methane, and oil shales. Supply costs for products produced from large scale oil sands mining at Athabasca and in-situ thermal recovery of the caliber at Cold Lake, place a ceiling on supply costs from untapped frontier oil resources and redirect (exploration) investment for oil away from these areas. In any event, Canada has the resource base to maintain crude oil production at over 2.0 million barrels a day into the foreseeable future since deficiencies from conventional light crude production will be replaced by supplies of upgraded crude and bitumen. Canada may be one of the few non-OPEC countries which already has the committed investment in place to increase oil supplies during the next decade (Littell, 1999, Figure 3) with output already planned to reach 2.8 million barrels per day by 2005.

Natural gas resources are sufficient to support production rates of up to 254 x $10^9 m^3$ or 9 Tcf per year but may not be sustainable or advisable. Continued high contributions will come from the Alberta portion of the Western Canada Sedimentary Basin (including the "fold belt") and its northern extensions (provided the intensity of drilling is maintained), east coast basins, (principally off Nova Scotia), the Mackenzie Delta and the shallow water areas of the Beaufort Sea. Again, gas supplies from remote areas may only proceed if alternative supply costs and large volumes of unconventional gas in areas of existing infrastructure do not undermine the projected investments.

Large amounts of Canada's petroleum resources may never be extracted: for example, natural gas is a North American continental commodity. Areas favorable for natural gas production in Canada must compete with other areas in the North American continent e.g. mid continent, Gulf of Mexico. The gas resources off Labrador, the oil and gas resources of the Arctic Islands and Arctic exploration generally (Figure 12) are areas highgraded here to remain orphaned, perhaps throughout the first few decades of the 21st century. The rate of production from massive oil sands deposits will forever fall short of potential capacity. This will be due to environmental demands, infrastructure requirements, demographic limitations in the workforce, and commercial (massive investment) considerations. A high proportion will remain reported as orphaned, stranded and "static".

Unless commodity prices drift differently from what they have over the past 25 years, the investment focus for the next 25 years is already in place. New conceptual plays remain illusive in spite of new technologies to visualize the subsurface and predict fluid contents in reservoirs "ahead of the bit." Nevertheless, significant ("trend changing") new reserves await discovery but these will only occur initially (to 2025) in those areas of recently implanted infrastructure (e.g. Jeanne d'Arc and the Scotian shelf) and in those areas of already known significant undeveloped resources requiring additional volumes to overcome development thresholds (e.g. Mackenzie Delta). Players who are not party to existing or planned infrastructure from these areas, may need to prove up initial stand-alone reserves to support alternative infrastructure or form co-operative ventures (including unitization) to guarantee threshold recoverable resources for the construction, funding and optimal development of them. If "alliances" or other commercial arrangements are not made, substantial investment risk is present since new "add-on" resources may not be brought to market for 10 - 20 years.

CONCLUSIONS

Overall, the Canadian petroleum industry is becoming a gas and oil sands business which will be further enhanced in the coming decades. The long-term future of the Canadian oil industry has to be in Alberta oil sands.

For the initial period of the 21st century, petroleum investment in Canada for the "big picture" and significant contributions to petroleum supply, will focus on five major areas (Figure 12):

1. "Mopping up" the Western Canada Sedimentary Basin; as major players vacate their non-core production, "smaller thinking" companies will continue the "drilling frenzy" for Cretaceous shallow gas and probe the deeper Paleozoic potential, particularly in the fold belt and extensions north of latitude 60 degrees North. The decline in conventional oil production will continue.

2. East Coast Scotian Shelf – the successful commissioning of the Sable Island gas project will encourage additional infrastructure expansion to serve the eastern seaboard gas markets, while exploration and appraisal on other shallow water shelf blocks will confirm and add to the reserve inventory. New wildcat wells will test prospects, particularly those in the "diapiric zone", in deeper water.

3. East Coast Grand Banks basins, particularly the Jeanne d'Arc Basin, will see Operators getting comfortable with oil production in this harsh environment and gradual uplift in the volumes of oil produced from this area. Effort will be directed to solving the gas production challenge and ice management.

4. Alberta oilsands - bitumen recovery and the manufacture of upgraded crude oil will continue to expand. Relative to frontier conventional oil, the product is low cost and competitively priced; the resource is effectively unlimited and non-depleting.

4. Mackenzie Delta/shallow Beaufort Sea resources – additional exploration will be needed to confirm adequate gas reserves prior to the construction of a connector to pipeline infrastructure to the existing gas and liquid pipeline systems to the south.

With global scenarios preaching the end of low cost oil (increasing production from OPEC) the utilization of abundant natural gas, alternative transport technologies and environmental commitments (Kyoto), the first 25 years of the next century will be as challenging for the Canadian petroleum industry as the last 100 years.

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CAPTIONS FOR ILLUSTRATIONS:

Figure 1-Sedimentary Basins of Canada. Sverdrup is the major basin of interest in the Canadian Arctic islands. Labrador includes the Hopedale Basin. Jeanne d'Arc is the most important basin on the Grand Banks. The basins of the Pacific Margin and Georges Bank off eastern Canada are subject to existing moratoria.

Figure 2-Location of Significant Resources of Canada as defined to date. Exploration activities have been conducted in all areas considered to offer the potential for major discoveries. Drake Point (170 x $10^9 m^3$ or 6Tcf) is the largest undeveloped gas discovery in Canada; Amauligak is the largest oil discovery in the Beaufort Sea; Taglu is the largest gas discovery on the Tuktoyaktuk Peninsula; the WSCB (Western Canada Sedimentary Basin) has produced the bulk of Canada's petroleum resources to date and is the site of the Athabasca oilsands; Venture is the largest gas field on the Scotian Shelf and underpins the Sable Island gas development inaugurated in late 1999; Hibernia in the Jeanne d'Arc Basin is the first oilfield to be developed on the Grand Banks; Bjarni is the largest gas discovery offshore Labrador.

Figure 3-Canadian heavy oil supply and demand (modified after Dingle, 1999a)

Figure 4-Location of the oilsands and heavy oil deposits in the Western Canada Sedimentary Basin. Llyodminster is the location of major upgrading facilities. Ft McMurray is the location of all the integrated mining plants (e.g. Syncrude and Suncor).

Figure 5-Canada's oilsands production history

Figure 6-Syncrude performance and outlook. Note the operating cost per unit of production has now fallen to approximately C$12.00 per barrel. This figure excludes capital recovery.

Figure 7-The Steam Assisted Gravity Drainage or SAGD process for in-situ recovery of bitumen (oil) from oilsands.